Planning of the Ontario Hydro East System

Part I · Volume 1

Report number 573 SP · June 1, 1976

Ontario Hydro

memorandum to MR. H.A. SMITH
Vice President
Engineering and Operations

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subject Planning of the Ontario Hydro East System - Report 573SP

Attached is a copy of Report 573SP dated June 1, 1976 and entitled "Planning of the Ontario Hydro East System". The report was prepared jointly by the Design and Construction, Finance, Operations, Regions and Marketing, and Services Branches and the System Planning Division. Report 573SP updates and expands many of the topics discussed in Report 556SP dated February 1, 1974 and entitled "Long-Range Planning of the Electric Power System".

On March 13, 1975 the Honourable Allan Grossman, Provincial Secretary for Resources Development, announced the Government's decision to establish an independent Commission of enquiry into the long-range planning of Ontario's electric power needs. The announcement stated that the Commission will focus on the broad conceptual consequences of alternative ways of supplying sufficient electric power during the period 1983-1993. It also noted that there are certain electric power generating and transmission projects that Ontario Hydro considers must be initiated during the tenure of the Commission. The priority projects are a generating station on the North Channel of Lake Huron, extra-high voltage supply lines to Kitchener, London and the Ottawa-Cornwall areas, and a second extra-high voltage transmission line out of the Bruce Generating Station.

Report 573SP has been prepared to provide background information for long-range planning studies and, in particular, the planning of the priority projects. The report discusses Ontario's growth in population, employment and productivity , electric load growth and forecasting, the principles used in generation and transmission planning, the major technical, economic, environmental and societal factors which are considered in the selection and design of the power system components, and the advantages and disadvantages of interconnections with other utilities. Also included is a discussion of present public participation and approval processes for major projects and suggestions are made for possible improvements in these processes.

Decisions on major electric power facilities in one part of the Province can affect the requirements for facilities in other parts. Report 573SP considers a number of alternative system arrangements for 1995 so that the need for the priority projects can be understood in a Provincial context. The Report illustrates how changes in the generation program and the location of generating stations can affect the arrangement of the bulk power transmission system by about 1995.

The alternative system arrangements are compared in the report based on the following three load forecasts:

1. The 1975 forecast of most probable loads which results in a 1995 load of about 57,000 MW. Most of the system arrangements are based on this forecast.

2. An illustrative lower forecast which results in a 1995 load of about 36,000 MW.

3. An illustrative higher forecast which results in a 1995 load of about 91,000 MW.

What the future load growth will be is unknown. The 1975 forecast of the most probable load growth is considered to be a reasonable basis for comparing the alternative systems. Changes in forecast load growth are not expected to make major changes in the system arrangements but may change the time when additional facilities are added.

MR. H.A. SMITH June 1, 1976

Report 573SP is being prepared in two parts. Part I which accompanies this memorandum consists of two volumes, with Volume I containing the text and Volume 2 the figures and appendices. Part II, scheduled to be issued later this year, will provide a comparison of the alternative system arrangements presented in Part I. This comparison will contain information on the environmental, cost and technical implications of the alternatives. Also, separate reports will be issued later on the priority projects.

INFORMATION COPY
ORIGINAL SIGNED BY
H. P. SMITH

H.P. Smith
Director of System Planning

PLANNING OF THE

ONTARIO HYDRO EAST SYSTEM

PART I · VOLUME 1

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PLANNING OF THE ONTARIO HYDRO EAST SYSTEM

PART I

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1.0 CONCLUSIONS

The purpose of the East System Report is to provide background data and information on planning the future development of the Ontario Hydro East System for the Hearings of the Royal Commission on Electric Power Planning and for reports to be issued at a later date on Ontario Hydro's priority projects. A more detailed discussion of the purpose of the Report and the events which led to its preparation is contained in Section 2.0.

The East System Report is being prepared in two parts. Part I consists of two volumes with Volume 1 containing the text and Volume 2 the figures and appendices. Part II, scheduled to be issued later this year, will provide a comparison of the alternatives presented in Section 12.0 of Part I. This comparison will contain information on the environmental, cost and technical implications of the alternatives and will offer conclusions thereof.

The following conclusions are of a general nature and their bases are outlined in the individual sections of Part I of the Report.

A. Section 3.0: Provincial Background

(a) There are many different and conflicting interests in society the resolution of which raise fundamental questions about the nature of the society in which we wish to live. Striking the proper balance in resolving these conflicting interests can only be done wisely when all sides of the questions are heard, long term views taken and mature judgements made in arriving at decisions.

(b) Since the earliest years of this century, Ontario has been transforming itself from an agricultural base to one in which manufacturing and service industries have come to play the dominant role.

(c) The plans of Ontario Hydro which are approved today will have a marked effect on economic growth and the quality of life in Ontario for decades. Prior to approval, these plans must be perceived as being in harmony with Government objectives.

B. Section 4.0: The Electric Load In Ontario

(a) Considerations of the supply and/or price relationships of oil and gas suggest that in the fairly near future a transition in energy supplies to Ontario is likely to take place. This may result in a cessation of growth or even an absolute decline in the consumption of oil and gas, or a transfer of use to coal and uranium from oil and gas. It indicates a change in energy use towards electricity.

(b) Any forecast of future electric load is subject to error. The risks introduced by error in the load forecast are two-fold: inadequate capacity due to underestimating the load, or excess capacity due to overestimating the load. Inadequate capacity may result in an unreliable supply; and this may cause direct financial losses to power customers and increased social costs to the province. Excess capacity may lead to financial risks resulting from inadequate revenues to Ontario in the short term, and the direct financial loss to power customers due to unnecessary high power cost in the long term. This means that the forecast effort should try to avoid error in either direction.

(c) The 1976 load forecast implies a continuance of exponential growth up to 1985, of about 6.8% per annum. Exponential growth cannot be be sustained indefinitely. However, further time must elapse before one can form a judgement on whether the electric load is continuing to grow exponentially or beginning to follow a declining growth pattern.

(d) The current projections of load growth are subject to increased uncertainties because of the effects of electricity price increases and personal incomes, availability and conservation of energy, and future government policies on energy supply and use.

C. Section 5.0: Principles of Generation Planning

(a) The dominant factors affecting the development and operation of the generation system are safety, reliability of power supply to customers, environmental effects and costs.

(b) There are many methods of assessing generation system reliability and improvements are continually being made to

existing methods. Regardless of the improvements being made in these assessments, judgements will always be required on the degree of reliability that should be provided.

(c) Provided there are no constraints on capital, it is Ontario Hydro's position that its reserve generating capacity in the 1980's should be in the range of 25% to 30% of the firm load.

A reduction in reserves will result in a rapid decrease in peak power supply reliability; but, the effect on the cost of power and long range requirement for new generating sites and transmission rights of way will be minor. If the reduction is obtained by deferring nuclear development, there will be a substantial decrease in the reliability of energy supply and an increase in the consumption and total expenditures for fossil fuels.

D. Section 6.0: Generation

It is concluded that in the period up to 1995:

(a) the major portion of the base load electric generation in Ontario can be provided most economically and most reliably by the installation of CANDU nuclear stations. Reserves and supplies of uranium in Canada should be adequate for such stations constructed beyond 1990, provided exploration and development are actively pursued over the next 10 years and export limitations are ensured;

(b) primary fuel reliance should be placed on uranium, provided the related capital requirements can be met. Any large additional consumption of fossil fuels should be in coal, although this should be limited because of concerns related to supply, cost and air quality. Further major commitments to use of oil and gas should be avoided, if possible, due to their relative scarcity and cost;

(c) most new nuclear and fossil-steam generating stations should be large central power stations located adjacent to major bodies of water. However, smaller power stations with multipurposes such as electric generation, steam production for district heating or industrial purposes, and refuse burning may become economic in certain locations; some of these may be located inland;

(d) none of the new technological alternatives currently being discussed in the public domain (solar power, wind power, geothermal power, fusion, etc.) is likely to have been sufficiently developed to be used as an economic and reliable generating source to form a significant component of the Ontario power system;

Wind power may have applications for electricity generation in remote communities. Solar energy will be used primarily for heating rather than electricity generation.

(e) to meet the growth in needs for reserve, peak load, and intermediate load generating capacity, and to replace fossil-steam generating units which have come to the end of their useful life, different combinations of further hydraulic and fossil-steam capacity and energy storage schemes may be developed;

(f) the only major sources of hydraulic energy remaining for development in the province are on rivers emptying into James Bay and Hudson Bay. One possibility is the development of the Albany River. This could have an installed capacity of about 3200 MW requiring the construction of about 15 power dams and several major river diversions. The development of this and other hydraulic projects is likely to be affected by economic social, and environmental considerations, and provincial policy with respect to the development of renewable resources;

(g) Ontario Hydro should continue to participate with Atomic Energy of Canada in programs for development of advanced fuel cycles involving thorium and recycled plutonium. This will permit the gradual replacement of uranium in the existing and future CANDU nuclear plants. This greatly extends the energy resources available to the province. It will ensure continued utilization and return on investment in the CANDU system;

(h) power and energy purchases from neighbouring utilities should continue to be investigated, and arranged when it is advantageous to do so. The magnitude and duration of such purchases are unlikely to be large enough to have any major long term effect on Ontario Hydro's generation program;

(i) As it may not be possible or desirable to install additional heavy water production capacity at the Bruce Nuclear Power Development subsequent to BHWP-A, B, C and D, it would be desirable and prudent for Ontario to make provision for heavy water production at another site.

E. Section 7.0: Principles of Transmission Planning

(a) An integrated power system, while requiring more extra-high voltage transmission, has a number of major advantages and is used by most major power systems.

(b) The selection of 500 kV for Ontario Hydro's future bulk power transmission system is appropriate because it provides a balance between the cost of construction, land use and future power transmission requirements. It also matches the existing 500 kV transmission system voltage from Northern Ontario to the Toronto area.

(c) Eight or more years are required to plan and build a major transmission line. Approximately 4 1/2 years of this time is involved in studies, public participation and approval procedures.

(d) The time required from the initiation of planning to placing the first unit of a generating station in-service at a new site is from 12 to 13 years.

(e) The use of HVDC will have limited application in the Ontario Hydro system up to 1995. Possible applications are a major interconnection with Quebec, an expanded interconnection between Ontario Hydro's East and West Systems and as part of the proposed Trans-Canada Grid.

(f) On the basis of reliability and land use, it is judged that the number of 500 kV 2-cct lines on a right of way should be limited to two.

(g) A Long Range Planning framework for the expansion of the generation and transmission network is required to avoid planning on a short term incremental basis which can result in higher costs, lower reliability and adverse environmental effects. The framework cannot be a detailed plan but should provide a guide for formulating current plans.

(h) The assessment of transmission system reliability has been largely based on deterministic techniques using a simulation method of contingency testing. New methods are being developed which will use probabilistic techniques to establish transmission reserves.

(i) Rebuilding existing transmission lines is one means of limiting the amount of land required for new lines. This approach has limitations because existing lines may be essential for the supply of load, they may not be in the appropriate location or the right of way may not be suitable for higher capacity transmission lines.

F. Section 8.0: Transmission

(a) It is expected that Ultra High Voltage transmission voltages above the 765 kV level will be required on a number of systems in the world in the next 10 or 20 years. In Ontario it is not expected that UHV voltage levels will be required before 1995.

(b) Turns in a transmission line require massive and costly angle towers. From a cost standpoint, the number of turns in a line should be kept as low as possible.

(c) Some people have expressed a preference for pole-type structures from an aesthetic point of view. These structures are heavier and costlier than conventional lattice structures.

(d) Transmission lines and stations are carefully designed, operated and maintained to ensure the safety of the public and operating personnel and to keep environmental effects such as RI, TVI and audible noise below acceptable levels defined or implied in the National Standards.

(e) HV and EHV cables have been developed for commercial use but they are at least an order of magnitude more costly than overhead lines and require massive quantities of materials as compared to overhead lines. The use of underground cable is expected to be confined to urban areas where existing developments prevent the use of overhead lines.

(f) The use of compact, gas-insulated (SF_6) switching equipment results in a major reduction in the land area required for transformer and switching stations. There

are no installations in the world of the size and voltage level which Ontario Hydro has purchased for its Parkway Belt Stations. The further use of SF_6 equipment will be contingent on successful operating experience as well as other factors such as future costs and availability.

(g) Ontario Hydro believes that there are no deleterious effects on human health from high voltage alternating current electric fields. However, the state of knowledge in this area is limited and Ontario Hydro plans an independent study of about 30 linemen and electrical workers who have been exposed to high voltage fields for at least five years. The study will be done by outside specialists and coordinated by the University of Toronto. An approach has been made to the Canadian Electrical Association to sponsor such a study.

(h) Transmission line routes and station sites are selected by a study process which involves the public in a comprehensive comparison of alternative means of satisfying a system need.

Any adverse effects from the construction, operation and maintenance of the facility are reduced by adherence to specifications and procedures developed to minimize these effects.

G. Section 9.0: Interconnections

(a) Interconnections with neighbouring utilities have many advantages in the areas of improved system reliability and reduced costs. Ontario Hydro's interconnections have been used to increase the reliability of its generation and transmission systems.

Reduced costs have resulted from day to day reduction in operating costs including purchases and sales of temporary excess capacity. Interconnections with the Provinces of Manitoba and Quebec have been used to import firm power.

(b) In future, if capital funds are insufficient to enable installation of Ontario Hydro's proposed generating capacity, it will be necessary to rely more heavily on assistance from interconnections.

(c) Ontario Hydro proposes to continue its ongoing studies on the expansion of interconnection capacity and to profit

where possible from reserve savings, firm purchases, coordinated development and operation.

(d) Expansion of the capacity of certain of the existing interconnections will require additions to internal transmission facilities.

H. Section 10.0: Financial and Economic Considerations

(a) The ranking of alternatives in terms of differences in internal economic efficiency is done by the discounted cash flow cost comparison.

(b) To a great extent, external costs and benefits associated with the operations of Ontario Hydro are incapable of quantification and, therefore, difficult to include in any decision-making evaluation. However, wherever possible, such factors are included in the decision-making procedure.

(c) Ontario's demand for electricity absorbs an important share of the total primary energy input to the Ontario economy. The two critical determinants of this situation are availability and price. A deterioration in either of these dimensions could lead to:

- a change in the lifestyle in the province;
- a deterioration of Ontario's competitive position with a consequent reduction in incomes and employment.

(d) Because of a scarcity in funds available for borrowing, it is foreseen that Ontario Hydro will not be able to take advantage of all the cost reduction opportunities available to it through the use of capital.

Methods of best utilizing available capital are under active consideration.

I. Section 11.0: The Decision Process and Public Participation

(a) Ontario Hydro is firmly committed to public participation in its present planning and it is clear that the general public and interest groups can provide valuable information and suggestions.

Nevertheless Ontario Hydro's experiences in the last four to five years have revealed that effective open planning is complex and difficult to achieve when applied to the expansion of electric utility facilities.

Some of the major concerns are the extended lead times, the difficulty of involving the public at an early stage of the studies, limited interest of the general public in Hydro projects and an absence of a clearly defined process for Government approvals.

(b) For major transmission rights of way and station sites, a two stage study process is suggested. This process has been used to form the basic plan for public involvement in future studies.

The first stage would establish the requirement for the particular addition to the system and examine the alternative plans to meet the requirement. In this stage the scope of the study would be broad with prime concern focused on Provincial impacts and major regional constraints. Primary public involvement would be with Government staffs and groups having a provincial or regional interest. Also in this stage, geographic areas would be defined for further detailed study.

The second stage would deal primarily with the specific location of the generating and transformer station sites and transmission line routes.

In the second stage the study would concentrate on the geographic areas approved in the first stage. Environmental studies would be more detailed and emphasis on public involvement would shift to the local level.

J. Section 12.0: Alternative Systems

(a) The most appropriate type of system development is one in which large generating units and stations together with the required bulk power transmission are used.

(b) Systems developed for the 1975 forecast of most probable loads are a reasonable basis for decisions on the near-term transmission and generation requirements.

(c) The preferred system alternatives are those in which the distribution of generation throughout this system is

reasonably close to being in proportion to the load distribution.

(d) Regardless of the distribution of generation, significant additional transmission facilities will be required in southwestern Ontario, in eastern Ontario and between northeastern Ontario and the Toronto area.

(e) Where it is reasonable to do so, transmission rights of way should be located close to potential generating station sites in order to increase the flexibility of future generating station siting.

(f) Systems in which large amounts of generation are located remote from the load have significantly greater transmission system power losses. These would increase the capital and operating costs of such systems.

(g) The development and operating costs of different generating station sites, when known, could have a large influence on the choice of system.

2.0 INTRODUCTION

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2.0 INTRODUCTION

2.1 General

On July 11, 1974 the Ontario Government announced it would hold public hearings into the long-range planning of Ontario's electrical power system. On March 13, 1975, the Honourable Allan Grossman, Provincial Secretary for Resources Development, announced in the Legislature the Government's decision to establish an independent commission of enquiry to hold these hearings. The Honourable Allan Grossman stated "The Commission will focus on the broad conceptual consequences of alternative ways of supplying electrical power during the period 1983-1993". This commission is now called the "Royal Commission on Electric Power Planning".

For planning and operating purposes, Ontario Hydro's facilities are divided into an East System and a West System, geographically separated by an imaginary line running north through Wawa.

This Report has been prepared to provide background data and information on planning the future development of the Ontario Hydro East System for the Royal Commission's enquiry, and for Ontario Hydro's reports on its priority projects. The latter are described later in this Section.

After a brief review of Ontario's growth in population, employment and productivity, the report presents Ontario Hydro's basis for forecasting load growth. The report outlines the principles which are used in planning the generation and transmission systems and the major technical, economic, environmental and societal considerations which go into the selection and design of the power system components. The benefits and disadvantages of interconnections are discussed and possible future interconnection developments are considered. Present public participation and approval procedures for major projects are outlined and ways of improving these procedures are suggested.

The report presents a number of possible alternatives for the bulk power transmission system and generating station locations for the year 1995. These alternatives are based on generation program LRF43P which was made obsolete when in February, 1976, the Chairman of Ontario Hydro responding to the direction of the Provincial Treasurer, announced a reduction in this system expansion program up to 1985 and beyond. The announcement came at a time when the work of developing the alternative systems was largely complete. Nevertheless, it is judged that program LRF43P is still a reasonable reference program for comparison of the conceptual systems described in Section 12.0 of this report. The possible effects of the cutbacks on load growth and on the timing for the facilities included in the program are more fully described in Section 12.0. A partial comparison of these alternatives is made. However, the data for a more

comprehensive comparison of alternatives is incomplete at this date. Further comparison data will be made available later.

The Honourable Allan Grossman's March 13, 1975 statement noted that there are certain electric power generating and transmission projects that Ontario Hydro considers must be initiated during the tenure of the Commission. These priority projects will be considered in detail in other reports which will discuss the requirement for additional facilities, consider the alternatives available, and how they fit in with the possible 1995 systems. The following three reports will be prepared:

- Supply to Ottawa-Cornwall Area

  This report will deal with supply to the Ottawa and Cornwall areas and with the question of reinforcing the electric interconnections from Ontario to Hydro-Quebec and New York State.

- Supply to Southwestern Ontario

  This report will deal with supply to the London and Kitchener areas, with a second 500 kV line out of the Bruce Generating Station, and with the future of electric interconnections between Ontario and the State of Michigan.

- Supply to Northeastern Ontario

  This report will deal with a generating station on the North Channel of Lake Huron and additional transmission from Northeastern Ontario to the Toronto area.

In summary, this Report on the Planning of the Ontario Hydro East System deals with the broad generation and transmission considerations involved in planning the Provincial electric power system and presents a number of feasible system arrangements for 1995. The above priority project reports will consider transmission line and generating station site requirements in three areas of the Province for which approval of plans are urgently required.

Ontario Hydro is initiating other studies which may have a significant effect on the development of the electric power system. These include:

- East System Generation Sites

  This will deal with the selection of four or more further sites for generating stations.

- Supply to the West System

  This will deal with the development of additional generation in the West System and the construction of

additional transmission between the West System and the East System.

2.2 References

Throughout this report, references will be made to documents that are available for public perusal at the Ontario Hydro library at 700 University Avenue, Toronto.

References 2.0(1), 2.0(2), 2.0(3) and 2.0(4) are Ontario Hydro documents dealing with its recent proposals for expanding its electric supply system.

2.3 The Electric Power Supply System

The power and energy which electric utilities supply to users of electricity is known as the electric load. Appendix 2-A describes the general characteristics of Ontario Hydro's electric load and the electric power supply system in Ontario.

Ontario Hydro supplies most of the electric power used in Ontario. It supplies this power directly to municipalities, to certain large industrial customers, and to individual industrial, commercial, farm, and residential customers in rural areas.

Within most municipalities, the responsibility for the distribution and sale of power lies in the hands of a municipal utility.

Power is also generated by some industries for their own purposes, and by some investor-owned utilities which distribute and sell power in areas of Ontario not now supplied by Ontario Hydro.

2.4 Reliability of Electric Supply

A. The Meaning of Reliability

The reliability of the electric system is the degree of continuity of full electric power supply delivered to the user's premises. The user's assessment of reliability is probably based not on the degree of continuity but its complementary aspects: the occasions in which the supply of power is interrupted completely or reduced partly (e.g., by severe voltage reductions or enforced reductions in power use). For this reason, the technical analysis of power system reliability concentrates on events which can cause power supply interruptions and reductions.

It is believed that users of electricity are affected by the following aspects of power supply interruptions and reductions:

(a) Their frequency, that is, the number of interruptions or reductions per month or per year. Frequent occurrences are more serious than infrequent ones.

(b) Their duration, that is, the length of time they last. Long interruptions or reductions are more serious than short ones.

(c) Their warning, that is, the amount of advance notice which Ontario Hydro can give the users. Interruptions or reductions which occur with no notice or inadequate notice are more serious than ones occurring with adequate notice.

(d) Their area, that is, are they widespread or confined to a small locality? To the community at large widespread occurrences are more serious than local ones.

(e) Their timing, that is, do they occur in the day or at night, on working days or weekends, in winter or summer? The effect depends on the user's activities at the time.

(f) Their cause, that is, do they result from factors which are capable of being largely avoided by Ontario Hydro, or do they result from factors beyond Ontario Hydro's control (e.g., floods, tornadoes, ice storms, etc.).

B. The Appropriate Level of Reliability

From the submissions to the Ontario Energy Board's 1974 Hearings on Ontario Hydro's Expansion Program and Rate Review for 1975, it appears that among users of electricity there are conflicting opinions concerning the need for continuing the present high level of reliability of the electric power system. Most of the municipal electric utilities favour continuance of high reliability levels. But some municipalities, some industrial users, and certain special interest groups suggest that the levels are too high and should be lowered in order to reduce the cost of electric power. It is Ontario Hydro's experience that many consumers, including large industrial consumers, expect a high level of reliability.

Some of the benefits of reliability upon users may be quantifiable, for example, lower production losses and costs, etc. Other benefits are difficult to assess, for example, personal comfort, or the value of personal safety from adequate lighting in public places, etc. The full effects of reliability include not only the effects that each user sees as applying to himself in isolation, but also the composite effect upon the community. For example, widespread and frequent outages may affect a manufacturer not only because his production capability is decreased, but also because they may interfere with his sources and costs of materials and with markets for his products. As another example, a worker in the manufacturing firm may suffer more as a result of interruptions in electric supply to that firm, than as a result of

interruptions in supply to his residence. It is also likely that deterioration in electrical supply may combine with and amplify the effects of possible future oil and gas shortages.

In theory, if one knew the dollar value of reliability to the entire community, and if one could accurately assess the reliability of the electrical power system, one could plan an optimum power system. This would be done by balancing the value of increased reliability to users and the cost of providing increased reliability from the system. Also, in theory, the power billing rate to each user could be varied according to the degree of reliability of his supply.

Ontario Hydro cannot now state the dollar value of various levels of reliability of the power supply to individual users and to the entire community. Also, electric utilities have not yet developed techniques to estimate the precise levels of reliability of power supply at the premises of individual users.

Ontario Hydro is conducting an extensive study of these matters. Results from this study on Reliability and Reserve Generation are not expected to be available for more than one year. The extent to which this study, or research by others in the utility field, will produce practical improvements in the planning process is uncertain. Until practical improvements are available, it is Ontario Hydro's position that, provided adequate capital funds can be obtained, it should continue the planning and design of its power supply system, using the methods of analysis and criteria that it has applied in recent years.

C. Technical Factors Affecting Reliability

From the viewpoint of planning and design, the reliability of the power supply system depends largely on three factors:

(a) The availability of its individual elements, i.e., the probability that individual elements will be in an operable condition. Elements are fossil-steam or nuclear-steam turbine-generators, circuit breakers, transmission lines, transformers, etc.

(b) The security of the system, i.e. its ability to continue to function adequately when it is subjected to sudden stresses.

(c) The availability of labour, equipment, and materials, which affect the design and construction of new facilities and the operation and maintenance of the system.

The methods of analysis and criteria used by Ontario Hydro are not applied to the power supply system as a whole. They are applied independently to separate sectors of the system, using only the most significant factors for each sector. These are:

(a) The availability of generating units.

(b) The security and availability of the bulk transmission system.

(c) The availability of the distribution system.

(d) The reliability of primary energy supplies.

Application of these methods to the separate system sectors does not ensure the correct relative level of reliability among the sectors.

D. <u>The Time Delay Associated With a Decision to Change Reliability</u>

A serious consequence associated with deciding to change reliability is the long time delay before the effects of the decision will be known. That is, on a site already owned it takes from six to seven years to construct and bring into service the first unit at a new generating station, for which all approvals have been obtained. If a new site must be acquired, the corresponding period is at least twelve to thirteen years. It takes more than seven years to establish new transmission and terminal facilities, for which routes and sites have yet to be acquired. Thus, current planning deals with capacity additions coming into service six or more years ahead.

Therefore, a decision to reduce reliability, and hence to reduce the addition of new generation and transmission facilities, may not produce a large effect on reliability for six or more years. But, if the decision is wrong and, as a result, six years from today it is found that the reliability is too low, it may take another six or more years to increase capacity additions and restore reliability to adequate levels. Thus, poor reliability may persist for six or more years.

2.5 <u>The Actual Process of Planning Ontario Hydro's Future Power System and Implementing Specific Projects</u>

Forecasts of future conditions are always subject to uncertainty. The further into the future that one extends a forecast, the greater is the uncertainty in the forecast; that is, the greater will be the likelihood of substantial differences between the forecast conditions and those which actually occur.

Uncertainty exists concerning many factors which affect the planning and implementing of Ontario Hydro's projects. It exists particularly with respect to:

- the future electric load which is determined by economic conditions and social preferences in the Province, and

- the alternative means that will be available to supply the future load.

The process of planning a particular change or addition to the electric power system involves two factors: determining the nature of the change or addition, and determining the time when it should come into service. With this information, one can determine the time at which it must be finally committed for design and construction.

In determining the nature of a facility, it is necessary to examine long range projections of future electric system development for periods up to 20 or more years ahead, in order to determine whether the proposed facility will:

(a) be needed in the long term;

(b) meet technical and financial constraints;

(c) meet expected environmental and social constraints;

(d) be capable of serving its intended function throughout its life;

(e) provide sufficient flexibility to allow Ontario Hydro to meet the uncertainties of the future; and

(f) permit future development of substantially superior projects, if and when they become available.

In determining the time when a facility is needed to come into service, and hence in determining when it must be committed for design and construction, the primary emphasis is upon:

- the load forecast from the present to the time the facility should come into service, and not on the load forecast beyond that time. In practice, this means the load forecast extending 10 to 12 years into the future.

- the alternative facilities which can be developed in this time span of 10 to 12 years. These alternatives are largely confined to those which are currently feasible from the technical, environmental, social, and cost viewpoints.

Recognizing the uncertainty of the future, it is not reasonable that Ontario Hydro have a single, specific, fixed, year-by-year program of new facilities for the next 20 years. In practise, such a program would have little practical value because it would be necessary to change it from time to time, as future events unfold. Therefore, Ontario Hydro's policy is to commit new projects only as their commitments become necessary, to attempt to ensure that they will be useful throughout their life, and to maintain flexibility for meeting actual conditions as they arise in the future.

2.6 References

2.0(1) Ontario Hydro, "Long Range Planning of the Electric Power System", Report 556SP, February 1, 1974.

2.0(2) Ontario Hydro, "Preliminary Submission to the Royal Commission on Ontario Hydro's Long Range Planning", May 1, 1975.

2.0(3) Ontario Hydro, "Submission to the Ontario Energy Board on the System Expansion Program, 1977-1982", four volumes, December 19, 1973.

2.0(4) Ontario Hydro, "Submission to the Ontario Energy Board", three volumes, February 28, 1974.

3.0 PROVINCIAL BACKGROUND

Inevitably a report of this kind is heavy with technical information. The engineering complexities and the province-wide scope of Ontario Hydro's activities are so large that the report may obscure the human needs that made them necessary in the first place. The simple fact is that the complex hardware of the electric system exists solely to serve the aspirations of Ontario society.

Since the first decade of the century Ontario Hydro has been sensitive to the needs of the province and has met them throughout this time with, relatively speaking, an abundant source of inexpensive power. However, we are now in a period when the population of the province has swollen, when its economy has become more diversified, and when its future needs have never been more difficult to forecast. Yet the future must be accommodated by plans laid today. Time will not permit us to take decades to adapt to new ways of living. Moreover, new facilities are expensive in a way difficult to conceive of in the past and they take longer to plan for and implement. The consequence of taking decisions on these facilities is that they cannot easily be reversed; that we and our children must live with them for a very long time.

But how does one predict the future? Technology can adjust to the objectives of society, but who can project with any certainty the objectives of our society? This society is made up of several levels of governments, numerous non-constituent groups, and the mass of the population at large. These may have different and conflicting interests.

For example, land is needed for the production of food, for living, for recreation, for industry, for resource development, etc. This leads to conflicts which may require trade-offs among the many basic objectives. The concern that food-land is being consumed by urban and industrial developments raises fundamental questions about the nature of the society we wish to live in. Ontario Hydro's increasing intrusion into the countryside is only one of many; for instance, there are sprawling urban developments, highways and pipelines, each making legitimate claims for land - and there is limited land to be parceled out. The whole problem lies in accommodating these claims and striking the right balance. This can only be done wisely when all parties hear all sides of the question, take the long-term view and use mature judgment based on their perception of the kind of life that the people of Ontario want for themselves and their children.

This means that planning is not only a responsibility but a practical necessity. Once the need for planning is accepted then it follows that action-decisions must be taken which will not necessarily please all sectors of society.

Ontario is a popular province; it has acted like a magnet in attracting people within its borders -- immigrants from within the country as well as from abroad. In June 1970 more than 7.6 million people ,36% of Canada's population, lived in the province. This meant that the population had grown by three million during the previous twenty years, or at an average growth rate of about 1.5% per year. Since 1970 the growth rate has not been quite as fast, but it has still been higher than that of most countries in the world and certainly higher than that of any other province in Canada. Reference 3.0(1)

The 1950s were heavy migration years as far as Ontario was concerned; the people who came here from abroad averaged about 83,000 per year. During the following decade this heavy influx of immigrants fell off somewhat and, it is estimated by the Ministry of Treasury, Economics and Intergovernmental Affairs, that immigration to Ontario during the 1970s will level off to some 50,000 a year.

Some of the factors that affect population growth in Ontario are: the emmigration policy of the Canadian government, the immigration policy of other countries and, of course, random political happenings that call for Canada to open its doors to the plight of the citizens of other nations. Thus, unpredictable surges in population will always be taking place. In any event it has been estimated that by 1980 Ontario will have a population of about 8.8 million.

The attractiveness of Ontario to potential immigrants raises a concern for all levels of government. A rapidly growing population gives rise to strain on all public services, may make public administration difficult, and may change the overall lifestyle. At the federal level there is a movement afoot to discourage the migration of people out of, for instance, the Maritimes through a policy of regional economic expansion. However, it would be unrealistic not to recognize that regional economic disparities will continue to lead to some internal migration. In the short-run at least there can be little doubt that Ontario will continue to draw population out of other areas in Canada.

One of the features about growth is that it tends to take place around existing urban and metropolitan centres -- the historical evidence for this is clear. The Economic Council of Canada predicts that the trend towards urbanization will continue in Ontario until 1980 when some 86 per cent of the population will live in urban centres.

The rapid growth of the population of Ontario is of fundamental importance to Ontario Hydro, but of equal importance is the changing nature of the employment of that population. In the most general way it can be said that from the earliest years of this century Ontario's society has been transforming itself, at varying speeds, from an agricultural base to one in which

manufacturing and the service industries have come to play the dominant role.

From 1951 to the present has been perhaps the most dynamic period of Canada's economic history. For instance, an Ontario Economic Council report says, "One major change was the increase in the size of the labour force. In 1951, Ontario's labour force totalled 1,883,000 members. By 1961, the labour force had grown to 2,393,000 and by 1970 it reached almost 3,200,000. In two decades one and a half million workers were added to the provincial labour force and about 60 per cent of these were immigrants." The same report goes on to say, "Between 1971 and 1980, the labour force growth will decline somewhat with an expected increase of 22.7 per cent (2.3 per cent per year). This will be much higher than the anticipated rate of increase in the population as a whole."

In addition to this, there have been changes in the industrial categories. There has, for instance, been a reduction of total production and employment in the primary sector, a relative stability in the share of the value of production and employment in the industrial sector, and substantial increases in the share of production and employment in the service industries. In 1951 the primary industries in Ontario (agriculture, forestry, fishing and mining) accounted for about 14 per cent of the labour force. The industrial sector (manufacturing, construction and utilities) employed about 41 per cent of the labour force. These two sectors together (called the goods industries) accounted for about 55 per cent of total employment.

The service industries have increased their share of employment throughout the whole period; by 1971 they employed about 57 per cent of all workers, compared with 45 per cent in 1951.

The emergence of the service industries has come about because of the growing urbanization of Ontario's population; an urban population demands a wider range of services than does a rural one. Thus cities and towns grow in size.

But the growth of service industries, which appears to be with us well into the foreseeable future, is not the only change that has taken place in Ontario society. Most industries are undergoing changes of a more or less fundamental nature.

In general, the trend has been in the direction of increased incomes for workers, which has been achieved because the province, until recently, has enjoyed inexpensive energy and materials as well as a reasonable cost for capital. The higher utilization of energy by industry has enabled average cost increases to be lower than wage increases.

The trend in agriculture has been to large farms in which specialization, improved technology, better management, higher

capitalization and limited use of labour play increasingly important parts.

Forestry too has seen a rapid growth in productivity. Production has gone up and employment has been reduced. This industry is a substantial energy user, particularly the pulp and paper sector.

During the 1951 to 1968 period the mining industry showed sustained growth. However, this did not lead to increases in the number of its workers, principally because it is one of industry's leaders in productivity. The industry's activity is closely related to government tax policy, and it is cyclical in nature. In general, the industry's heavy energy use is confined to areas outside the urban centres.

In 1969, the construction industry employed about 6 per cent of the labour force. It is a flexible, vigorous industry and when non-residential construction declines, the residential variety tends to grow and can account for 40 per cent of total output. Essentially, the construction industry is related to the health of the economy; it is a function of investment which, in turn, relates to profit levels, interest rates and future expectations. The industry is not, comparatively speaking, a heavy energy using industry. This could change, of course, if in the years to come the price of new housing leads to the founding and developing of a new industry, such as factory-made houses. Most industrial categories are becoming more energy intensive as well as getting larger in scope.

The most revolutionary change that has taken place in Ontario's business environment is in manufacturing which is naturally energy dependent. At the beginning of the century manufacturing was quite rudimentary by today's standards. However, since that time, it has increased in scale and complexity. It is historically interesting to see how this came about. In the early part of the century most of Ontario's manufacturing capability was directed to meeting the needs of the province. Raw materials produced on farms and in the woods were processed to meet the needs of farmers. It was the opening of the west in the late 1800s that increased the demand for a more diversified range of manufactured goods needed by settlers. It was during this period that the establishment of motor vehicle and other transportation industries took place. Following this there was a development in the manufacture of agricultural implements which, in turn, necessitated the development of the fabricated iron and steel industries.

The Second World War stimulated a tremendous growth and diversification of Ontario's manufacturing sector. The motor, aircraft and shipbuilding industries expanded dramatically to meet the war effort. The production of synthetic rubber was started on a commercial scale because natural rubber supplies

were cut off. In addition to this, the manufacturing sector in Ontario had to meet consumer needs for textiles, apparel, shoes and many other consumer goods that had been cut off because of lack of overseas supplies. Ontario's manufacturing capability did not fall off after the war; in fact, it increased substantially.

As a result of all these historical forces, the manufacturing sector has continued to develop and mature in Ontario up to the present day. In fact, the leading industries in the province in terms of the number of people employed and the value of goods produced are in the manufacturing sector.

Uncertainties in the international trading environment make it hard to say what will be the future trend for Ontario's manufacturers. The industry successfully came through the period of serious readjustment of the late '50s but various questions still remain: how open will be the world's attitude towards trade, will the Canadian dollar rise in value and thus cut us off from export markets, can the Ontario manufacturing sector rationalize itself in the direction of greater competitive efficiency, and will our manufacturers be successful in gaining access to foreign markets, particularly that of the United States? It is upon the answer to questions such as these that the future growth of the province depends.

Naturally if the province's manufacturing industry continues to develop the way it has in recent years, there will be an increasing demand for electrical energy.

In a recent sociological-geographical study carried out at Queen's University by Professor Maurice Yeates, and published in 1975 under the title, Main Street (See Reference 3.0(2)), a developing phenomenon of significance has been foreshadowed and analysed. The book deals with the growth of a strip of land designated "the axis". This strip of land measures 700 miles long by 125 miles wide and contains some 12 million people. It stretches from Windsor to Quebec City and therefore extends itself beyond Ontario Hydro's area of interest. However, some facts concerning this axis are of direct interest because they relate to growth within Ontario Hydro's area of jurisdiction.

The axis is growing faster than any other part of the country and the people who live there are, on average, wealthier than those in other parts of the country. In 1971, 53.3 per cent of Canada's population lived in the axis and, in 1970, 72 per cent of the employment in manufacturing was located there. The Ontario part of the axis is growing fastest; this is because of higher birthrates and because people from other parts of Canada, as well as the world come to live here. Growth, naturally, tends to accumulate around the four chief urban centres: Toronto, Montreal, Hull-Ottawa, and Quebec City.

This Windsor-Quebec City axis appears to be almost an independent functional entity in the country, with commercial

and industrial activity thickening up between the two powerful ends, Montreal and Toronto.

The author of Main Street goes on to suggest what the axis will be like in the year 2001, saying that by this time, the population will probably have reached 19 million, with a comparative shift of the population to the Ontario portion of the axis. In fact, he goes so far as to suggest that within this time span, 35 per cent of the axis's population will be located within 40 miles of Toronto.

Clearly such trends are of fundamental concern to the Government of Ontario, and indeed have been under active consideration by its Ministry of Treasury, Economics and Intergovernmental Affairs in a series of publications that appear under the generic title: Design for Development. These publications have dealt in considerable detail with such slower growth areas as: Lake Ontario, St. Clair, Georgian Bay and Eastern Ontario. In these publications, charts, graphs, and demographic information is set forth in analytical fashion to enable the people of each region to consider options for future development.

Some generalizations arising out of these publications, together with other matters have been included with recommendations in a subsequent report published by the Ontario government entitled: Directions for Economic and Social Policy in Ontario. (Reference 3.0(3))

In this report the Government recognizes, among many other things, that economic performance must be compatible with social objectives and quality of life; that decentralization of economic activity must take place to reduce pressure on urban areas; that immigration should be more responsive to Ontario's need to overcome gaps in skill availability; that steps should be taken to diversify the industrial base in northern communities; that economic and social policies should be seen in a more unified and co-ordinated way and one that leads to a decentralization of economic activity.

If the recommendations of this Government report are acted upon, then they will encourage a better distribution of economic activity within the province and one consistent with an improving quality of life, also the development of a "set of co-ordinated policies designed to promote balanced and progressive development consistent with the varied hopes and needs of Ontario citizens".

Ontario Hydro is aware of the sociological significance of its actions. The needs of people have never been so great, nor so insistent, and Hydro's place in the overall energy picture has never been so problematical. Yet beyond all this there is the need to prepare ourselves to meet the energy demands in the years ahead. The facilities Ontario Hydro puts in place today will have a marked effect on economic growth and the quality of

life in Ontario for decades. However, they cannot be implemented without it being perceived by all that they are in harmony with Government objectives.

The essential question faced by Ontario Hydro is how best to align its plans for system development with objectives proposed by the Ontario government for growth and economic decentralization.

REFERENCES

3.0(1) "Ontario: A Society in Transition" published by the Ontario Economic Council, 1972

3.0(2) "Main Street" Maurice Yeates, Queens University; McMillan, 1975

3.0(3) "Directions for Economic and Social Policy in Ontario", Ministry of Treasury, Economics and Intergovernmental Affairs, August, 1974

4.0 THE ELECTRIC LOAD IN ONTARIO

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4.0 THE ELECTRIC LOAD IN ONTARIO

A. Summary

This section outlines the factors affecting the growth in electric load, the importance of the load forecast to system and financial planning, and the considerations in and methods of forecasting load growth. It includes comments on the use of load projections for Ontario which imply that future reductions will occur in the rate of growth.

Considerations of the supply and/or price relationships of oil and gas suggest that in the fairly near future a transition in energy supplies to Ontario is likely to take place. This may result in a cessation of growth or even an absolute decline in the consumption of oil and gas, or a transfer of use to coal and uranium from oil and gas. It indicates a change in energy use towards electricity.

Any forecast of future electric load is subject to error. The risks introduced by error in the load forecast are two-fold: inadequate capacity due to underestimating the load, or excess capacity due to overestimating the load. Inadequate capacity may result in an unreliable supply; and this may cause direct financial losses to power customers and increased social costs to the province. Excess capacity may lead to financial risks resulting from inadequate revenues to Ontario in the short term, and the direct financial loss to power customers due to unnecessary high power cost in the long term. This means that the forecast effort should try to avoid error in either direction.

The 1976 load forecast implies a continuance of exponential growth up to 1985, of about 6.8% per annum. Exponential growth cannot be sustained indefinitely. Analysis of the Gross National Expenditure for the period 1926 to 1975 indicates that its future may follow a Logistic Projection. If the past correlation between Ontario's East System primary peak demand and the Gross National Expenditure persists, this implies that the East System peak demand will also follow such a projection. However, this is not necessarily the case for this type of projection does not fit the past record of electric growth. Moreover, the electric load projection obtained by correlation with the Logistic Projection of Gross National Expenditure falls within the range of error obtained by exponential projection of the electric load. Therefore, some further time must elapse before one can form a judgment on whether the electric load is continuing to grow exponentially or beginning to follow a declining growth pattern.

The current projections of load growth are subject to increased uncertainties because of the effects of electricity price increases and personal incomes, availability and conservation of energy, and future government policies on energy supply and use.

B. The Ontario Energy Setting

The decades of the twentieth century have seen fundamental shifts in energy flows into the Ontario economy and equally fundamental changes in the associated technologies which in turn have led to profound changes in the standard and style of living.

The first of these shifts was the harnessing of hydro-electric power to complement energy from coal and wood. The second was the coming of the internal combustion engine and the rise in importance of petroleum as a significant energy source. Electricity and the internal combustion engine produced revolutionary changes in productivity in the farm sector and the goods producing sector of the economy. The third major shift occurred with the arrival of natural gas in significant quantities from Western Canada in 1955. The fourth was the advent of nuclear power, which like hydro-electric energy is based upon an indigenous energy resource. Nuclear energy seems likely to dominate developments in the next few decades.

Figures 4-1 and 4-2 are energy balance statements for Ontario and show the energy flows in 1959 and in 1972. The energy flows in these years reflect the effects of a period when natural gas was penetrating the market, oil was completing the process of dominating the transport market (replacing coal in the railroad and marine sectors), and the last major hydro-electric developments in the southern part of the province had been completed.

The figures show the source and disposition of the various forms of primary energy in the Province of Ontario. An important disposition is conversion to electricity, which is a secondary form of energy as are gasoline, coke, and blast furnace gas. Electricity, is currently provided from all sources of primary energy. Other products generally come from some particular primary source (eg, gasoline from oil), although changes are in prospect as coal promises to become a much more important source of secondary energy.

It should be noted that the heading "Final Demand" used in the figures is a somewhat simple term for the disposal of a single year's energy. Industrial demand in particular is not necessarily "final" in that the products of industry are intermediate for the most part to some other final use. It would be useful for energy budgeting purposes to be able to estimate for example, the energy content of an automobile, a house, a mile of highway, or for that matter a Candu nuclear plant.

In the following table, which is derived from figures 4-1 and 4-2, the equivalent per cent annual compound rate of growth is calculated for energy supply between 1959 and 1972. The shares of the total, by type of fuel and by source, are also shown for each of the two end years.

Item	Ontario Primary Energy Supply Equivalent % Annual Growth Rates 1959-72					% Share of Total Primary Energy Supply	
	Coal	Oil	Gas	Hydraulic	Total	1959	1972
Production in Ontario	0	-.98	-2.59	1.77	1.59	28.8	19.2
Imports from Outside Canada	3.01	-4.52	1.78	0	2.25	27.2	19.7
Imports from Other Provinces	-8.68	4.79	18.31	0	7.47	44.0	61.0
TOTAL	2.80	4.23	15.33	1.77	4.80		
% Share of Total Primary Energy Supply							
1959	23.3	42.8	6.8	27.1		100.0	
1972	18.1	39.9	23.5	18.5			100.0

This table illustrates the following points:

(1) Production from Ontario's oil and gas resources has been declining. There has been little growth in hydro (and little is expected).

(2) Growth in imports from outside Canada has been substantially less than growth of energy in total. (Oil and gas imports from the United States will probably become limited to exchanges or specialty products, but coal imports may continue to increase.)

(3) Imports of energy from other Provinces, with the exception of coal have increased substantially. (It is unlikely that the rates for oil and particularly for gas are sustainable, but the declining trend in coal transfers may be reversed.)

Figure 4-3 shows the Canadian Mineral Energy Resources estimated in 1973. In reports on the prospective supply and requirements of oil and gas (References 4(1) and 4(2)) published in 1975, the National Energy Board has indicated that there are likely to be difficulties in supplying the Canadian market from domestic production in the early 1980's. The longer run supply prospects for gas appear to be reasonably favourable, but those for oil indicate that Canada may have to resort to imports to an increasing degree, with the attendant balance of payment problems. This would appear to indicate that the Canadian market will not be insulated from world price levels for much longer. The following table shows the percentage of Ontario's

supply of Mineral Energy in 1972 (from Figure 4-2) and the percentage proven reserves in 1973 (from Figure 4-3).

	Per Cent of Total			
	Oil	Gas	Coal	Uranium
Ontario supply in 1972	48.9	28.8	22.3	0
Canadian proven reserves, 1973*	9.5	9.0	42.4	39.1

*Excluding tar sands and heavy oil

The relative composition of coal, gas, and oil supplies into Ontario are similar to that prevailing elsewhere in Canada and North America.

The prospects of supply and/or price difficulties in oil and gas suggest that a transition is likely to take place in the fairly near future towards energy supplies which are in greater balance with the reserves of non-renewable fuels. This can be accomplished in two basic ways:

- by a cessation of growth or even absolute decline in the consumption of oil and gas, or

- by a transfer of demand to greater use of coal and uranium.

If the growth in demand for total energy is sustained at or close to the rates prevailing in the 1959-72 period, a transition of substantial proportions is likely to become extremely urgent. At the same time, a transition towards coal and uranium inputs implies greater emphasis on electric energy.

The recession which affected all industrial countries following the Middle East oil crises of 1973 has had the effect of slowing the growth in total demand for energy, and this is true of Canada and Ontario as well. If recovery from this recession is slow, then the urgency of the transition problem will not be as immediate. However, if the present economic slowdown is not a permanent transition to a lower rate of economic growth (which many people maintain is the case), but, only a temporary phenomenon, then it is possible that the problems facing electricity supply could become severe in the early 1980's.

To provide some perspective on how such a transition might occur, the following is derived from Figures 4-1 and 4-2:

Ontario Energy Final Demand
Equivalent % Annual Growth Rates 1959-72

	Coal	Oil	Gas	Sub Total	Electricity
Exports	3.1	13.1	N.A.	17.7	3.5
Transport	-12.7	5.1	0	4.6	0
Domestic & Farm	-19.1	1.5	8.7	2.0	6.4
Commercial	-14.2	15.2	20.7	11.0	11.7
Industrial	- 2.2	4.2	16.0	3.8	4.4
Total	- 3.9	4.5	14.7	4.58	6.1

This table indicates that some shift in demand towards electricity, but away from coal, was taking place between 1959 and 1972, especially in domestic and farm consumption, and to a lesser extent in commercial and industrial.

It should be noted that in Figures 4-1 and 4-2, it is not valid to compare BTU inputs of the various fuels (and especially electricity) to final consumers. This is because of the difference in utilization efficiencies. For example, most of the conversion losses in producing and using electrical energy are suffered before its sale to the final consumer, whereas for other fuels, the final consumer suffers the losses. This is reflected to some extent in the prices per BTU of the various fuels. The point is important insofar as a shift to electric energy may convey the impression of less efficient utilization of primary fuel inputs. However, insofar as one regards useful work as being the commodity demanded by consumers, such an impression is misleading. Unfortunately no agreed estimate of utilization efficiency by final customer exists.

It is very likely that oil and gas furnaces are considerably more efficient than coal-fired residential furnaces. For example, a shift from coal to gas may involve a reduction of 10 tons of anthracite coal (254 million BTU) and an increase of only 200 million BTU of natural gas - a net reduction in total energy demand. Thus, there is a productivity gain to be considered when attempting to reckon real growth in useful work. For this reason the apparent energy growth shown in the above table for the combined domestic and farm consumption of coal, oil, and gas furnaces is probably too low at 2.0%.

It should also be noted in connection with growth in both Domestic, Farm, and Commercial demand, that prior to 1959, electric space heating in Ontario was virtually forbidden.

The above table and figures 4-1 and 4-2 show that oil has gained a virtual monopoly in the transportation field. It seems unlikely that coal will stage a comeback in either rail or marine transport, for reasons of labour cost and air quality. Coal energy demanded by the transport sector declined by an average of 12.7% per year from 17.6 in 1959 to 3×10^{12} BTU in 1972. It should be noted, however that the period witnessed

not only the disappearance of coal as an input, but also of passenger rail service generally. Also, much of the rail freight business was lost to trucking, and therefore to oil. There exists a possibility of electrification of some rail transport.

The possibilities of electrification of road transport over the next couple of decades cannot be dismissed. The present state of the art, however, is inefficient and capital intensive. The capital intensity of rail electrification has tended to impede its widespread adoption in Canada to date, although it is quite widespread in Europe and South America. This remains a distinct possibility in Canada, but even fairly extensive rail electrification is unlikely to add substantially to electrical demand. For example, electrification of the Toronto-Montreal link would add load in the order of 200-250 average megawatts - about 700 kilowatts per mile. It might, however, reduce the demand for petroleum by a greater amount.

Confronted with the prospect of oil and/or gas shortages, industrial consumers will probably face real options in switching to either coal or electric energy. The direction of such transfers would be determined by technological constraints, relative prices, and by the cost of compliance with environmental standards. It should be noted that one possibility of switching from natural gas to a coal source may be the use of manufactured gas. Tar sands do not offer promise of solution.

In both the residential and commercial markets, the net probability at present indicates that the tendency of any change of fuel source will be towards electric energy. This is particularly true in commercial applications where the internal source heat pump provides an advantageous method of utilizing energy. Residential heat pumps have not been developed to the same degree, but the prospects are that either heat pumps or some alternative will be developed to supplement the existing resistance type heating. There is also the possibility of the development of hybrid systems which make use of the storage of solar energy.

To the extent that the market is relied upon to accomplish the transfer of energy flows, three comments are perhaps in order:

The first comment concerns developing trends in the pricing of electric energy in Ontario. In the 1960's, Ontario Hydro was confronted with exhaustion of its significant economic hydraulic resources before the CANDU nuclear technology had been fully put in place. As a result, the Lakeview, Lambton and Nanticoke coal-fired plants were built to supplement Hearn and Keith. In addition, oil-fired plants at Lennox and Wesleyville are currently under construction or planned. These plants will probably be at the margin of production for years to come. They have high energy costs and relatively low capital costs. The result is that the charge to the customers for electric energy may tend to be high relative to the demand

charge. Therefore the incentive for customers to invest in storage and peak shaving schemes will be considerably diminished compared to recent experience.

On the other hand, if the electric energy charge is kept below the short run cost of producing an extra kilowatt-hour of electric energy, the charge per BTU of electric energy may fall below the price of competing fuels, with the result that those customers who face electric demand charges but are operating at load factors below 100% would tend to substitute electric heating for other forms. The existence of this prospect gives rise to increasing uncertainty about the future load factor and consequently about the optimum mix of kinds of generating equipment.

A second comment relates to the price prospects for the various fuels. If oil and gas are scarcer than coal and uranium, this would be reflected in a free market by higher costs (and prices) for the former than for the latter. The response of demand to this situation should then tend to increase the demand for coal and uranium and to decrease it for oil and gas depending upon elasticity, which in turn is a function of the customer's costs involved in substituting one energy source for another. The result of these demand forces would be towards price equality. There are signs, however, that the pressure for price equality of fuels may come from the supply rather than the demand side. Evidence of this rather disturbing tendency can be seen in the trend towards horizontal integration with the emergence of so-called "energy companies" who are active not only in oil and gas but also in coal and uranium. If the push to price equality comes from the supply side, then the required transfer of fuel types will tend to be impeded.

A third comment concerns the availability of capital. Most people think of capital as money. However, as Douglas Peters (Vice-President and Chief Economist, Toronto-Dominion Bank) recently pointed out (Reference 4(3)), if there is a constraint, it should be thought of as one of physical capital - that is the men and materials who can be made available to put the required plant in place. Should the economy be underemployed, then this is a sign of spare and unused physical capital.

During the depression of the 1930's, the economy virtually ground to a halt, and it was virtually impossible to finance expansion, because of lack of markets. As recently as 1963 there was a problem of a stagnant economy - with things needing to be done, idle resources available to do them with, and no apparent way to bring them together. These are failures of human institutions, not of physical capital. The Canadian economy at present is underemployed, in spite of its problem of inflation.

As an example of a shortage of physical capital, M. King Hubbert (Reference 4(4)) has shown that the supply of finite non-renewable resources such as oil and gas tend to grow

exponentially up to a point. Thereafter, although demand may continue to grow exponentially, the rate of discovery fails to keep up and ultimately starts to decline. Conventional reserves of oil and gas in North America reached their maximum point in this process in the late 1960's. In the United States, a gas gap has developed, the oil gap is being filled by imports, and the latter event is the basis of the energy crisis of 1973. The prospects are for world supplies to encounter the same limits sometime in the 1990's.

It does not necessarily follow that the growth in total energy demand will slow down so long as a viable alternative is available to sustain the energy flows. It seems likely that coal and uranium will be able to do this for Ontario well into the 21st century. The implications, however, are for sustained and perhaps accelerating growth in the demand for electric energy.

C. Load Forecasting in Relation to System and Financial Planning

At the present time, Ontario Hydro's objective is to provide generation and transmission facilities which will supply the expected load at the lowest feasible cost subject to constraints of safety, reliability, environment, and financial integrity.

The planning process begins with the load forecast. At least once each year, a complete review is made of the load forecast for the following ten years. In the interval between the successive annual reviews, the progress of actual load growth and economic conditions is monitored and, if necessary, revised forecasts are issued to reflect conditions different from those contemplated when the last complete annual review was made.

The risks introduced by error in the load forecast are two-fold: inadequate capacity due to underestimating the load, or excess capacity due to overestimating the load. Inadequate capacity may result in an unreliable supply; and this may cause direct financial losses to power customers and increased social costs to the province. Excess capacity may lead to financial risks resulting from inadequate revenues to Ontario Hydro in the short term, and the direct financial loss to power customers due to unnecessary high power cost in the long term. The load forecast effort is therefore preoccupied with reducing error to a minimum. In practice, this means that the forecast effort should try to avoid consistent error in either direction. Therefore, the forecast is designed not to be biased in either direction.

There are two dimensions to the load forecast. The first is the "most probable" load, which is defined as that load which has equal probabilities of being too high or too low; it is the expected or most likely load. The second is an estimate of the distribution of error associated with the forecast. The estimated error enables the system and financial planners to

assess the risks to which any proposed plan is subject. The general plan which stands up best under a wide range of possible outcomes is the best plan, even though it might not stand up as well under the actual outcome of events as some other particular plan might have. The difference in cost between the general plan and the particular plan is the cost of risk.

It is possible that the forecast may give rise to a general plan that is unattainable or unacceptable under existing criteria. Under such circumstances, it is necessary to obtain assurance that the level of the forecast is reasonable. This is a difficult exercise for the following reasons:

(a) The easiest way to solve the problem may seem to be to adjust the forecast so that the resulting plan is attainable and acceptable. For example, under present conditions, when the economy is slack and is strike-ridden, there is an abundant evidence to suggest that the load forecast should be lowered. Yet the record shows that under similar circumstances in the past, when the forecast has been lowered, it has almost invariably been lowered too much. By the same token, in the past the forecast has been raised unduly when it was made under buoyant economic conditions.

(b) It is often argued that the future will not be like the past, and therefore, that forecasting by analogy with the past is invalid. However, this begs the question, because it is necessary to specify just how the future will differ from the past. This line of thought may lead to an implicit assumption that the future will be simply an extension of the present - which, as noted above, has been a poor course to follow in the past.

(c) An exponential growth cannot be sustained indefinitely. Therefore, it is sometimes argued that any forecast which shows exponential growth, even for relatively short future periods, is too high. This type of argument prevailed in some forecasts made 20 years ago, with disastrous results. No one knows whether it may be correct at present.

Any forecast that is decided upon at a time when the level of the forecast is a matter of a serious controversy may be subject to a greater error than might be the case in the absence of controversy. Whether or not such a forecast will lead to a change in the general plan of development may depend upon the degree to which the load forecast error affects the planning decision. For example, in the above case, the load forecast of most probable load may be lowered, but the load forecast error may be increased. However, the general plan of development may not change greatly if the increase in load forecast error is fully taken into account.

In any case, it is important to have some idea of the possible amount of unsatisfied load, because this is a measure of the

cost to power customers and to the economy against which the savings to the electric utility arising from reduced generation levels must be assessed.

The stability of successive load forecasts is also a matter of concern. Forecasts should be as accurate as possible, and if they are completely accurate, they will not change. Because they are not accurate, they do change from one year to the next, due to access to new information. However, frequent reversals in forecast levels are disruptive to the general plan for development. Therefore, a change in forecast levels should probably be made only if there is reasonable assurance that the direction of the change will not be reversed the next time around. Thus, stability in the forecast from one year to the next is a desirable attribute, although it is not a forecast procedure. The advantages of stability may be outweighed by the effects of change in conditions from one year to the next.

D. Forecasting Considerations and Methods

(a) General Remarks

In January 1974, the Ontario Energy Board examined Ontario Hydro's Load Forecast in considerable detail. The following description of the process of growth is taken largely from Volume 2 of Hydro's Submission to the Ontario Energy Board of December 19, 1973 (Reference 2.0(3)). The description of the Load Forecasting process is also based on the submission, but has been rewritten in the light of the cross-examination by Counsel for the Ontario Energy Board. This evidence brought out the vital part played by regional personnel in preparing the forecast, because they modify the results of the forecasting model in the light of intimate local knowledge. The other important aspect brought out in testimony was the fact that the load forecasting process, by virtue of its geographical detail, does not isolate the effects of global economic and social causes. These must be inferred from the results of the forecasting process, and if these results do not appear to be reasonable in the light of expectations about the economy, then the application of judgement is called for - either by way of modifying the forecast or by way of decisions which may be made concerning an adequate level of reserve capacity.

(b) The Process of Growth

For the past 53 years, the East System Primary Peak Demand has grown at a fairly steady average rate of 6.8 per cent per annum, with annual rates varying from a minimum of -6.5 per cent in 1931 to a maximum of 15.2 per cent in 1939. Both years witnessed events that can be regarded as extreme - namely the onset of the Great Depression and the outbreak of World War II. Within the last seven years, annual growth has ranged from a high of 11.7 per cent in

1968 to a low of 0.4 per cent in 1974. These latter extremes reflect a growing sensitivity of peak demands to weather.

Fluctuations in the business cycle have been less severe since World War II. There seem to be two reasons for this growing stability in economic conditions, and they are reflected in load patterns. One reason is that industrial loads, related to the production of goods, have been growing somewhat less rapidly than other sectors of demand, and consequently the cyclically sensitive industrial demand is becoming a smaller portion of the total. The same is true of the economy in general. The second reason is that as the Ontario economy has become larger, it has become more diversified and consequently there has been an increased offsetting of short-term trends in one sector by those in another. This is true of the East System, but not of the West System which remains primarily a region specializing in staple resources (pulp and paper, gold, base metals and iron mining) which tend to be very sensitive to economic conditions. A variant of the second reason is to be found in the growing multiplicity of end-uses for electric energy in all sectors.

Weather fluctuations and economic fluctuations are quite different in their impact on the system. While both are random and unpredictable, the duration of fluctuations due to weather is short; that of economic fluctuations is prolonged over a matter of years. In medium range forecasting (the next decade), appropriate to Ontario Hydro's generation lead time, it is therefore much easier to deal with weather fluctuations than it is to cope with the business cycle. For one thing it is relatively easy to define expected or normal weather conditions, and extremely difficult to do the same thing for economic conditions. Moreover, there are structural changes going on in society which profoundly affect the demand for electric energy over the long run - events such as sustained rates of immigration, birth rates, the urbanization of Ontario, the shift from single family dwelling units to apartments, and the growth of tertiary industry already mentioned. More recently there has been a growing concern with environment and the quality of life. The impact of this concern upon the demand for electric energy gives rise to considerable uncertainty. A great deal of the concern has focussed on the production of electric energy, and the parallel concern with exponential growth has tended to focus upon growth in energy consumption in general and electric energy consumption in particular as evils to be avoided.

At the same time, the importance attached to the quality of the individual's personal indoor environment has led to a growth in air conditioning and electric heating. Insofar as cleaning up the atmosphere and the Provincial

waterways is concerned, some industries and municipalities can comply only by introducing electrically powered equipment for recycling and removing materials from their effluents. Since October, 1973, there has been growing concern with not only the price, but the availibility of primary fuels, especially oil and gas. The result, on balance, seems more likely to portend an increase in the rate of growth of the demand for electric energy.

Electricity differs from most other forms of energy in that it is a product which is manufactured, and which can be made from almost any other type of energy. Consequently, it is able to draw upon more technical alternatives than any other energy source, and this may tend to make its price more stable over the longer run.

Generally speaking, the demand for electric energy has grown more rapidly in its mature phase than other types of energy. Electricity has therefore acquired an increasing share of the energy market in Ontario with the passage of time. In a very general way one can think of the growth in demand in these portions - that due to increasing population accounting for something slightly in excess of 2 per cent, with the 4.7 per cent per capita increase consisting of a "normal" increase in the order of 3 per cent and the balance representing a shift to electric energy from other types. The prospects for the future, seen from this perspective in time, call for a moderation in the rate of population growth (depending upon fertility rates, net migration to Ontario from other provinces and Canadian immigration policy). While subject to considerable uncertainty, the prospects for the shift seem to be further towards electricity depending upon relative prices and availability of other fuels, the availability of capital and the thrust of public environmental policy.

(c) <u>The Effects of Price and Personal Income</u>

The effects of price and incomes upon the growth of demand for electric energy are extremely difficult to assess.

In the industrial sector, the technical coefficients (units of electrical energy input per unit of output) do not seem to be expecially stable within an industry and of course they vary considerably between industries. The prospects are that using these coefficients will prove even less rewarding in the future than in the past, due to the amount of consumption of electricity that is related more to pollution abatement than to production.

The commercial sector which is growing most rapidly, has undergone considerable change in its nature of use of electricity, and there is uncertainty as to the future pattern of use.

Because residential consumption is relatively homogeneous (in comparison with industrial and commercial), it lends itself to a greater degree to statistical analysis. What has been observed is that residential consumption is very responsive to incomes. This shows up very clearly in a study of municipal residential consumption since World War II. This study shows a remarkable stability in the relationship: monthly energy consumption is approximately the amount that can be purchased with the earnings from three hours of work. During the period, appliance prices and rate structures have remained relatively stable, but incomes have risen substantially.

Much more difficult to estimate is the response of residential consumption to price. Part of the difficulty stems from the residential block rate which makes average price depend upon consumption. This makes it impossible to observe the effect of price upon consumption. In the absence of significant changes in the rate level, it is not possible to observe anything more than a series of points on different price-quantity relationships. However, in cases where there have been abrupt changes in rate level (such as Chapleau in 1965), it is possible to estimate what consumption would have been in the absence of the rate change, and hence to estimate the effect of price upon consumption. From this, crude estimates of price elasticity can be made.

Studies to date indicate that elasticity is also a function of time. A customer's consumption of electricity by use of the particular stock of appliances that he owns probably does not respond immediately to any change in the price of electricity. However, a customer may greatly increase his stock of appliances and his use of electricity if there is a significant reduction in the price of electricity.

Whether the relationship would hold in the case of a price increase is open to doubt, since customers would probably have to suffer a loss in order to dispose of appliances. In some cases (e.g. rental water heaters) where competitive forces permit an easy substitution without the customer suffering a capital loss, the adjustment can be quite drastic and rapid. In other applications, such as electric heating, the consumer has less freedom of choice, but nevertheless the impact upon new business could be significant. In the long run, the relevant price in each application is the price relative to competitive services.

This is an important area in which ignorance of the process persists. With the prospect of increases in all energy prices, but with variable timing of the impacts on different fuels, the medium term (next decade) uncertainly is quite large. As mentioned previously, the long term outlook for the relative price of electricity is that it may tend to become more attractive if only because of the

larger number of technical options open in the process of its manufacture.

(d) The Effects of Government Policy

The effects that government policy may have upon the magnitude of total growth in Ontario is not known; but it is expected that it may have a considerable impact upon the geographical distribution of that growth. This will depend upon the degree to which market forces are overcome or redirected by government policy. It appears that unfettered allocation of growth in Ontario by existing market processes may lead to a socially untenable development. While there is almost complete agreement with this premise, there is no such unanimity on any particular alternative to it, and consequently the details must evolve through the political process. This complicates the forecasting problem in that political forces must be taken into account. It is necessary to forecast the outcome of the process which may prove to be quite different from the intent. This may pose problems in forecasting, and will require at least that some provision for uncertainty be made in these forecasts.

(e) The Forecasting Process

The process of growth described in the previous section consists of inferences drawn from observation and study of growth in the demand for electricity in Ontario and elsewhere over many years. The description is an effort to relate the growth process in a general way to the wider economy and the society in which it operates. Such a description has explanatory merits, but it lacks the precise quantitative relationships which are required for it to have merit for prediction. For one thing, a forecasting approach based upon explanatory social and economic variables requires not only a reliable forecast of those variables, but a means of translating them precisely into electrical demand in Ontario. Means of doing so which yield better results than existing methods are not presently available. Moreover, the requirements call for the geographical distribution of electrical load in Ontario as well as the time path of system demands. For these reasons, the forecasting approach in Ontario consists essentially of forecasts of individual customers' peak and energy loads which are accumulated into totals which are then translated into peak and energy demands by introducing estimates of diversity and/or losses. In some cases, it may be necessary for loads to be forecast for customers who may not now exist. Ontario Hydro uses the term "unallocated load" to describe the effects of such loads.

Negative allocated load can also be used to reduce the forecast in circumstances where judgement indicates that the total estimate for a class of customers is too high

while it is not possible to isolate which particular forecasts are wrong. For example the total forecast for a group of paper companies may be unreasonable, but in the absence of a detailed assessment of the competitive position of each company, it is not possible to modify individual forecasts. Some further detail on the method of estimating unallocated load is contained on page 13 of section 2.0 of Volume 2 of Reference 2.0(3).

The load forecasting system in Ontario Hydro combines the use of a mathematical model with the application of the detailed knowledge of individual customers which is available from Ontario Hydro personnel in the field, and within utilities, areas, and direct customers served by Ontario Hydro. The reasons for adopting this detailed approach over that of deduction from global social and economic causes are twofold:

i) It appears to produce aggregate or system forecasts of greater accuracy than any deductive mathematical model which has been applied to date.

ii) It produces the needed geographical detail of customers peak demands which is needed for system planning purposes, while a model using explanatory social or economic variables would tend to yield annual energy, perhaps by end-use category, which would then require disaggregation into monthly energy by geographical unit and translation into peak load.

The fact that this approach produces forecasts with smaller errors than other methods is not altogether surprising when one considers that it brings to bear more relevant information than is the case with even the largest econometric model. As the time horizon extends into the future, the available knowledge peters out, and consequently greater emphasis tends to be placed on mathematical techniques.

The system suffers from the disadvantage that it is hard to persuade the public that changes in explanatory economic and social variables such as birth and immigration rates, incomes, changing consumer preferences and the like are captured by the approach, but they are not isolated by it. For example, increased load by virtue of concern for the environment may show up in the forecast as a new sewage plant in a municipality and some additional pumps in paper mill, but this load may or may not be specifically identified by its cause. Similarly, declining birth rates will show up in altered plans for housing types and quantity, but once again the cause will not be identified although it may be speculated upon after considering trends in the aggregate forecast. Moreover, the classification system into customers' loads is primarily geographical and administrative rather than by

end-use classification, except perhaps for the direct industrial load. In any event, even if end-use classifications were available, they would refer to energy, most likely on a annual basis, and it would be extremely difficult to convert such predictions to peak load on a monthly basis with the required geographical distribution.

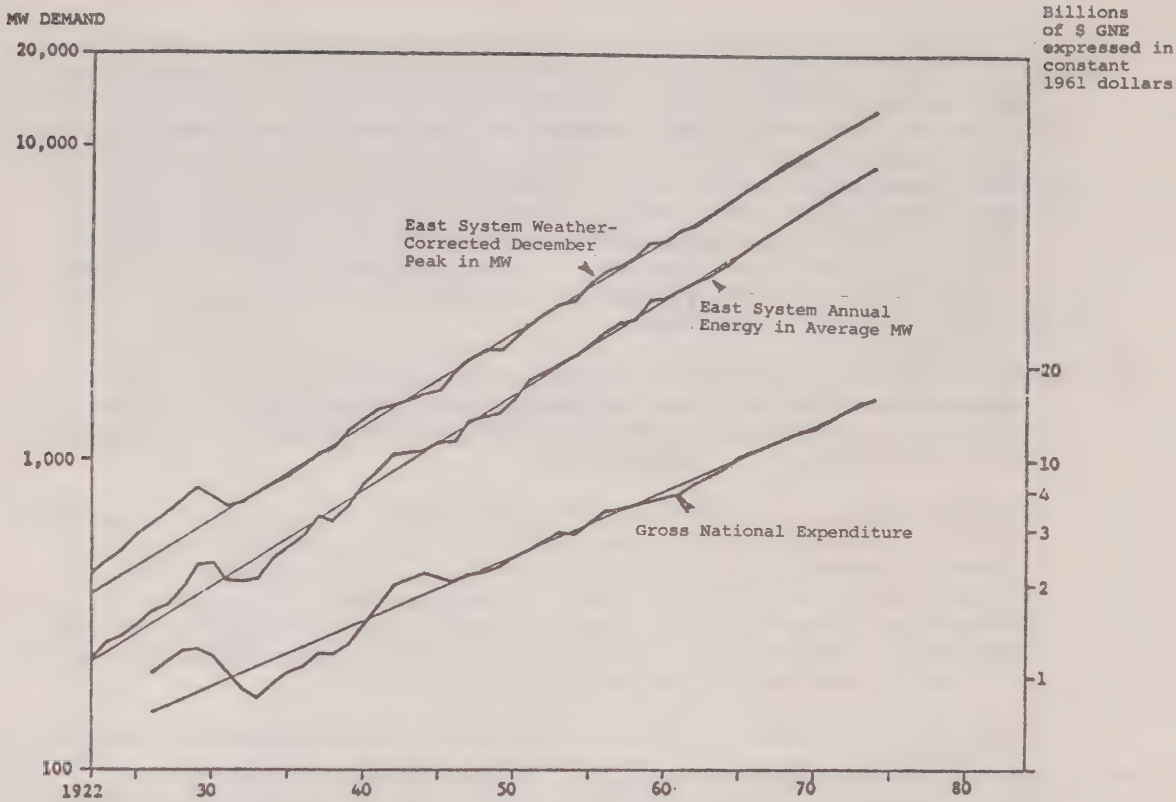
Consequently, the forecasting process as it exists differs from the process of growth as it has been described. Nevertheless, some understanding of the process of growth provides a useful background against which to assess the results of the forecasting process in an attempt to answer the vital final question: are the results reasonable?

No forecast carries with it any guarantee of accuracy, and the occasional forecast can be badly in error. In assessing these bad forecasts it is useful to have available for scrutiny a general statement on expectations at the time the forecast was made. A forecast is "bad" only if a better one could have been made with the information on hand at the time. Anyone can make a good forecast with the benefit of hindsight. Similarly, an assessment of the uncertainties associated with the forecast gives its users some appreciation of the risks that they run, and often provides an insight into the cause of subsequent forecast error.

E. The 1976 Forecast in Relation to Historic Trends

In order to place this forecast in some perspective, it can be linked to the wider Canadian economic environment by virtue of a mathematical relationship, which although imperfect, has been reasonably stable for a great many years.

This can be illustrated to some extent by the following figure which shows the East System Weather Corrected December Peak and annual Energy Demand 1922-1975, and also annual Gross National Expenditure (GNE) for Canada 1926-1975 in real terms expressed in constant 1961 dollars. The latter is the most comprehensive measure of the physical goods and services produced by the Canadian economy. Accompanying each of the three series is a least squares trend line fitted to the 1926-1975 period.



For the East System December Peak loads, the relation between the 1976 load forecast and simple time model projections is as follows:

YEAR	1976 LOAD FORECAST			PROJECTIONS OF SIMPLE TIME MODELS			
	Most Probable Load (Normal Weather)	Weather-Corrected Load	Annual Growth in Weather-Corrected Load	Prediction with Autoregression		Projection of 1926-1975 Least Squares Trend of Weather-Corrected Loads	
				Load	Difference	Load	Difference
	MW	MW	%	MW	%*	MW	%*
1976	14,793	14,733	6.76	14,873	-.95	15,265	-3.49
1977	16,044	15,861	7.66	16,009	-.93	16,344	-2.95
1978	17,308	17,197	8.42	17,213	-.09	17,501	-1.74
1979	18,491	18,265	6.21	18,492	-1.23	18,739	-2.53
1980	19,740	19,471	6.60	19,853	-1.92	20,064	-2.96
1981	21,043	20,701	6.32	21,303	-2.82	21,484	-3.64
1982	22,471	22,106	6.79	22,849	-3.25	23,003	-3.90
1983	23,999	23,609	6.80	24,499	-3.63	24,631	-4.15
1984	25,631	25,215	6.80	26,260	-3.98	26,373	-4.39
1985	27,374	26,930	6.80	28,142	-4.31	28,239	-4.63

* Difference is the deviation of the 1976 Weather-Corrected forecast from the projected value.

The 1926-1975 Least Squares trend has an annual trend growth rate of 7.07%, with a standard error of 3.12%. Deviations of actual past loads from the 1926-1975 least squares trend tend to be negative for years which are generally regarded as years of recession and they also tend to be positive for boom years. Consequently, the 1926-1975 least squares trend line may be thought of as a good estimate of the level of East System Weather Corrected Peak under "neutral" economic conditions (neither boom nor recession), which assume steady growth at 4.86% for the Canadian Economy. (This is the slope of the 1926-1975 trend for GNE).

The prediction with autoregression assumes that any current departure from the least squares trend constitutes either a peak or a trough, and the prediction incorporates an asymptotic return to trend in future years.

On this basis, an economic interpretation of the 1976 forecast is for growth which is significantly lower than historical growth. Growth in the years 1977 and 1978 is higher than average and reflects a modest recovery from the current recession. However, the trend levels are not forecast to be regained. Low growth rates in 1979-1981 result from a bunching of completions of projects in 1978-1979.

The lower forecast in relation to the least squares trend line is justified in part by an economic outlook which has deteriorated both with respect to the prospects as seen in 1975 and with respect to historical patterns. Moreover, the prospects in 1976 indicate that efforts to conserve all forms of energy are going to be more vigorous at the government level than appeared to be the case last year. It should be noted, however, that Ontario Hydro's forecasts in the past have tended to be too low when made during periods of economic recession, just as they have tended to be too high when the forecast has been made in times of boom. The 1976 forecast bears some striking technical resemblance to the forecast made in 1963. If this should prove to be the case, then the prospects are that the 1976 forecast will prove to be too low.

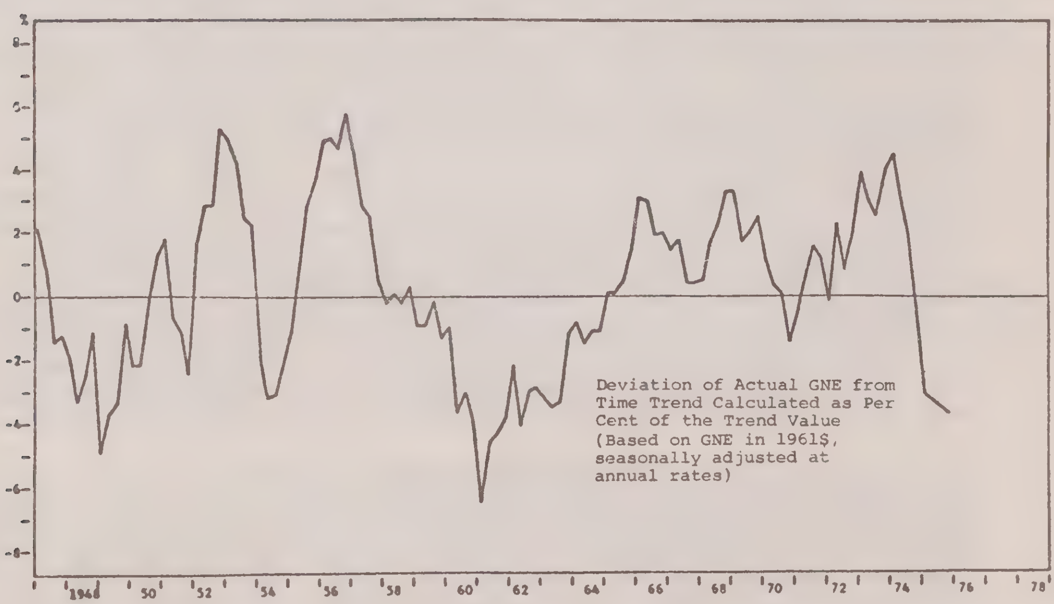
The relationship of East System Primary Peak Demand to Real Gross National Expenditure, calibrated for the period 1953-1975 is:

$$E(\text{Log Peak}) = .00231 + 58536 \text{ Log GNE} + .017029(\text{YR} - 1900)$$

This relationship yields a peak load estimate of 14037 Mw for 1975, compared to the December weather corrected value of 13,800 Mw - a difference of 1.72%. This is within the standard error of the model which is 2.6%. The model can be used to translate forecasts of Gross National Expenditure into forecasts of the East System Primary Peak Demand. This permits a check to be made upon the reasonableness of Ontario Hydro's

Load forecast. Where the two are in close agreement, it does not follow that either is correct, but such an event does provide some ground for increased confidence in the result. Where a forecast of load derived from a forecast of Gross National Expenditure yields results which differ considerably from Ontario Hydro's forecast, confidence is reduced and it becomes necessary to seek an explanation.

The following Figure shows the deviations of Real Gross National Expenditure in 1961 dollars from its 1947-1975 time trend of 4.89% per annum (which compares to the annual trend of 4.86% between 1926-1975). The quarterly data shows the profile of post-war booms and recessions and thereby provides some perspective to the present economic situation.



The figure indicates that the peak of the most recent boom was reached in the first quarter of 1974. The quarterly GNE (in 1961 dollars) in relation to the trend is as follows:

Quarter or Year		Actual	Annual Growth	Trend	% Deviation of Actual from Trend
1974	I	79.5	7.1	76.1	4.5
	II	79.4	-.5	77.0	3.2
	III	79.4	.1	77.9	1.9
	IV	78.4	-5.0	78.8	-.6
	Year	79.2	3.7	77.5	2.2
1975	I	77.3	-5.5	79.8	-3.1
	II	78.1	4.0	80.7	-3.3
	III	78.8	3.9	81.7	-3.5
	IV	79.7	4.3	82.7	-3.7
	Year	78.5	-.9	81.2	-3.4

The series reached a local maximum, and a peak departure from trend in the first quarter of 1974. It reached a local minimum in the first quarter of 1975, and since then there has been growth, but at a slower rate than historic trend. Consequently, the deviation from trend was still widening in the fourth quarter of 1975. Recovery from the recession will not be apparent until the growth rate from quarter to quarter exceeds an annual rate of 4.89%, in order to make up lost ground. What remains to be seen is not only when the recovery will get under way, but whether it will be sharp and short as in 1954 (the post-Korea recession) or flat and prolonged as in 1959-1965.

The least squares prediction model incorporating autoregression assumes in its forecasts of GNE that any departure from trend constitutes either a peak or a trough, and the forecast incorporates an asymptotic return to trend in future years. This forecast is shown as the expected value of the historical trend in Figure 4-4 and suggests a value of $114.0 billion for 1976 measured in $1971. Upper and lower limits are also shown for this prediction. These define a range within which there are 58 chances in 100 that the actual value will occur.

An alternative hypothesis concerning economic growth is currently arousing renewed interest. This hypothesis attempts to come to grips with the fact that exponential growth is not infinitely sustainable, and must ultimately be constrained by upper physical limits. The two principal empirical curves that have been developed to incorporate this hypothesis are the Gompertz and Logistic curves, with the latter imposing the lower ceiling. It is not possible to fit either of these curves to East System data 1922-1975, as the Gompertz curve indicates hyper-exponential growth, and the Logistic curve

needs evidence of an inflexion point. However, both can be fitted to Real GNE 1926-1975. The Logistic curve yields the values shown in Figure 4-4 on the basis of an upper limit of \$618 billion which is 5.7 times the 1975 value. The curve predicts that the growth rate is currently 4.1% and will drop to 3.8% in 1985 and 3.25% in 1995. That is to say, it predicts growth rates actually experienced in the last three quarters of 1975. However, by 1985, the Logistic projection is still above the lower confidence limit of the prediction with autoregression, which means that the choice between the hypothesis of saturation and the working hypothesis of exponential growth must be deferred, probably beyond 1985.

The twelfth annual review of the Economic Council of Canada (1975) published late in 1975 contains a number of projections of rates of growth of Gross National Expenditure. Three of these have been translated into levels, and are shown on Figure 4-4. They are:

i) the control projection (what is expected);

ii) the potential path of GNE at full employment, and

iii) an attainable target towards which economic policy should be directed.

Figure 4-5 shows these forecasts as percentage deviations from the 1926-1975 Least Squares trend of GNE.

In Figure 4-6, the Gross National Expenditure predictions in Figure 4-4 have been translated to East System Peak Demands on a weather correct basis. The 1976 forecast is also shown for comparison.

In Figure 4-7, deviations from a base which is the least squares projection of GNE are shown. Figure 4-7 indicates that the 1976 load forecast is lower than the loads corresponding to the Economic Council's forecast, and also below the least squares projection. It is interesting to note that the Economic Council forecast is above the prediction with autoregression.

Figure 4-7 therefore seems to indicate that in addition to being low by historical standards, the 1976 forecast is also low if the effect of Gross National Expenditure is taken into account. This means that a choice exists between:

i) the forecast is too low, or

ii) the GNE projections are too high, or

iii) other factors are operating.

F. Effect of Other Factors

(a) Price

The history of the demand for electric energy in Ontario is one of falling prices in real terms. It is also true that the prices of utilization equipment, notably appliances, have also been falling in real terms. These factors, other things being equal, would tend to stimulate the demand for electricity. However, the prices of alternative fuels have also been falling until recently. The decline in the price of gas after 1955 has been particularly dramatic. With the price of all major forms of energy falling in real terms until the early 1970's, there has undoubtedly been a shift in Ontario towards more intensive use of all forms of energy. About half of the growth in total energy demand in Ontario (excluding transportation use) can be explained by changes in Real GNE, which can be considered as capturing income and population changes. It seems reasonable to assume that the other half may be accounted for by changes in prices, technologies and attitudes towards the use of energy. Thus as the real price of all forms of energy rises, it seems likely that the demand for energy will grow less rapidly for given changes in GNE.

The degree of these changes in the real price not only of electricity, but also of other fuels is not known with any precision. Increases in the price of electricity will tend to reduce the demand for it, other things being constant. However, increases in the price of substitute fuels will tend to shift energy demand towards electricity in the absence of other changes. Consequently, the effects of price increases in all forms of energy are offsetting, subject to their combined depressing effect on the demand for energy generally.

During the span covered by this forecast, it seems likely that:

- oil prices in Canada will move to the international level;

- gas prices will move to heating content parity with oil.

If such price movements offset the increased prices of electricity, then it would appear that the forecast may be too low (apart from any total impact on energy demand in total). However, increasing energy prices tend to have an indirect effect on incomes, in that customers seem likely to spend a higher proportion of their budget on energy and

less on other things (such as appliances) in response to an increase in energy prices.

The timing of price changes in the various fuels may prove to be crucial in that a possibility exists for large, but transient responses to occur. This gives rise to considerable uncertainty in the forecast.

(b) Availability and Conservation

While the 1976 load forecast was being prepared, Ontario Hydro's system expansion plans were deferred to a degree that the outlook for the reliability of electric power supply after 1979 will change radically from past standards if the 1976 forecast demands materialize. A deterioration in the quality of the service may reduce the demand for it in much the same way as an increase in its price. At the same time, the availability outlook for alternative fuels seems to be more promising than in 1975; thus the risk of a massive shift to electric heating for example, may have diminished.

Exhortation to the public to save all forms of energy has accelerated in the past year. The Federal Department of Energy, Mines, and Resources is currently sponsoring an advertising campaign aimed in part at reducing the demand for electric energy. However, the campaign to date has dealt principally with commercial consumption at night.

Following the completion of the 1976 load forecast, the Ontario Hydro Board adopted a policy of aggressive conservation designed to limit the rate of load growth. In connection with this policy, targets for load reduction of energy and peak demand have been prepared. They are not included in the 1976 forecast. However, as the efforts come to bear fruit, the results will tend to be captured by the load forecasting process, and to that extent will become embodied in future forecasts. It should be noted, however, that the forecasting process does not have the capability of identifying or isolating such influences.

(c) Weather Effect on Winter Peak

For a number of years, the East System winter peak demand occurred in December, usually in the full working week before Christmas unless extremely cold weather was encountered earlier in the month. The January peak occurred early in the month. Weather corrected demands used to come to a sharp peak in the week before Christmas, probably owing to extensive decorative lighting that was common before 1973. In the new year, they would drop off

rapidly. For a number of past years it has been evident that January peak demands are growing more rapidly than December, probably due to electric heating, and forecasts for a number of years have reflected this.

With the former sharp weather corrected seasonal pattern peaking in December, the period during which cold weather could significantly result in an increase in the winter peak load was very short. Because the period of exposure was so short the forecast December and January peaks were assumed to occur under normal temperature conditions.

More recently, and particularly since 1973, with decorative lighting load probably having declined, the weather corrected pattern of load has become quite flat from early in December until early in February. This means that the winter peak load now seems likely to occur on the coldest working day between the first week in December and the first week in February. That is to say, the period of exposure has lengthened dramatically.

The weather effect to be expected in a "normal cold weather spell" is currently estimated at 1.6% of the weather corrected peak demand. However it has been observed that the system is becoming more temperature sensitive, and it is expected that the "normal weather effect" may increase from 1.6% to over 2%.

It is interesting to note that the winter peak in 1975/6 occurred on February 2; the second highest peak was on January 22. On both days temperatures were more than 30^{o}F below normal.

(d) Uncertainties and Risks

It should be noted that this reduction in 1976 of the East System forecast is the second significant reduction in two years, and it continues a pattern which except for the forecasts of 1973-4, has been in evidence since 1969. This is illustrated by the following pattern of forecasts for the load in 1984:

Forecasts Made in	Forecast for 1984	% Change from Previous Year's Forecast
1968	27,792	
1969	28,537	+2.68
1970	28,444	- .32
1971	27,977	-1.64
1972	27,429	-1.96
1973	27,560	+ .47
1974	28,264	+2.55
1975	26,899	-4.83
1976	25,631	-4.72

The 1926-74 trend value for 1984 was 26,761. Incorporating the 1975 data dropped the value to 26,373. The 1975 forecast value was above the trend value and drifting towards it. The 1976 value is below trend and, like last year's forecast is growing less rapidly than trend.

The planning process at Ontario Hydro can accommodate itself to orderly changes in forecasts, but it tends to be severely disrupted by oscillating forecasts. Even though the change in the 1974 forecast was trivial, its reversal in the 1975 forecast caused severe disruption to the planning process.

Lowering any forecast increases the risk of upside error, just as increasing it increases the risk of downside error. The change in the outlook cannot help but be conditioned by what has happened in the recent past, and the fact that forecasts have tended to be high for the past few years is strongly suggestive of bias, even though this experience may be totally irrelevant to a year like 1984.

In fact, the record of the past shows that forecasts made in periods of recession have invariably proven to be too low, and forecasts made in periods of boom have invariably proven to be too high, as shown in Figure 4-8.

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5.0 PRINCIPLES OF GENERATION PLANNING

Contents

Appendices (Bound in Volume 2)

5.0 PRINCIPLES OF GENERATION PLANNING

5.1 Summary

Electricity can be generated in many alternative ways. The selection of a satisfactory program for generation development involves the following steps:

i) Determine the requirements for new generating sources.

ii) Determine the restrictions in the manner in which the requirements can be met.

iii) Determine the feasible alternatives, i.e., those which meet the requirements and conform with the restrictions.

iv) Compare the feasible alternatives by weighing up and trading off their advantages and disadvantages.

v) Identify the best alternative, when all factors are considered.

The dominant factors affecting the development and operation of the system are safety, reliability of power supply to customers, environmental effects, and cost. The trade-off process among these factors is somewhat different at the planning and the operating stages.

The cost and other characteristics of generation alternatives and the nature of the electric system load lead to the planning of new generating units to operate primarily in one of four modes: base load, intermediate load, peak load, and reserve. Reserve is not unused generation, but generation which comes into use whenever operating generation becomes unavailable for any reason.

Reliability is a matter of degree, not of absolutes. The various methods of assessing generating system reliability and the value of reliability to customers are incomplete and are under continuing study. Regardless of the improvements made in these assessments, judgements will always be required on the degree to which money will be spent to provide reliability.

Provided there are no constraints on capital, it is Ontario Hydro's position that its reserve generating capacity in the 1980's should be in the range of 25% to 30% of the firm load, and that nuclear generation should be developed as rapidly as feasible in order to provide for a reliable energy supply.

One should use caution when considering a reduction in reserves. The peak power supply reliability will decrease rapidly, but the reduction in estimated cost of power and the effect on the long range requirements for new generating sites and transmission rights of way will be minor. If the reduction is obtained by deferring nuclear development, there will be a substantial decrease in the reliability of supplying energy and an increase in the consumption and total expenditure for fossil fuel. Reducing the reserve may also decrease Ontario Hydro's ability to meet environmental constraints.

5.2 General Remarks

Usable electric energy does not occur naturally, but must be manufactured (i.e., generated) from energy in other forms. Except to a limited extent it cannot be stored; therefore most of it must be used instantly.

Each user could produce his own electricity by purchasing oil, natural gas, coal, hydrogen, etc., and generating electricity on his own premises. In some cases, water power could be used. Because of the costs, environmental effects, and complexities of electric generating equipment, this do-it-yourself method has not been used on a wide scale. Instead, electric utilities have been formed to generate electric energy and distribute it to users. The location of large hydroelectric resources and the economies of scale for thermal generating stations have resulted in electricity being generated mainly in large generating stations instead of a myriad of small stations located through the areas in which electricity users are located.

5.3 Factors Affecting Decisions at the Planning Stage of Generation Development

A. Safety

A prime objective is safety to the public and to employees of Ontario Hydro. Safety always has been, and will remain an inherent requirement in the design, construction, and operation of generating facilities.

B. Reliability of Power Supply to Customers

The objective is to supply the electric needs of customers as reliably as possible, with due regard to the trade-offs that may be necessary among reliability and the other factors.

No generator is completely reliable. Generators become unavailable for full operation from time to time because of breakdown, lack of fuel, environmental limitations, need for periodic maintenance, and many other factors discussed in Section 5.4. The individual large fossil-steam and nuclear generating units used by Ontario Hydro are generally available

about 7000 out of the 8760 hours per year. However, it is necessary to have enough generation available to supply the electric load for all hours in the year. Therefore, to meet this requirement, reserve generation must be provided and kept in readiness to replace any operating generator when it becomes unavailable.

Each generator could be designed and operated to supply a fixed proportion of the total electric load at all times that it is operating. In this case, it would operate at low outputs during nights and weekends, higher outputs during daytimes, and highest output at times of daily peak electric load. However, because of the costs and operating characteristics of generation which are discussed in Section 6, current practice is to design generation to operate primarily in one of the following four modes:

(a) Base Load

This is generation which operates at full output most of the time that it is available.

(b) Intermediate Load

This is generation whose energy output is produced chiefly during the daytime periods. Technical limitations may prevent some types of intermediate load generation from being stopped and started each day; and for such types, it may be necessary to operate at high output during the daytime periods, and at minimum safe output during the nighttime.

(c) Peak Load

This is generation whose energy output is produced chiefly during the daily peak load periods. Technical limitations may prevent some types of peak load generation from being stopped and started each day; and for such types, it may be necessary to operate at high output during the daily peak load periods and at minimum safe output during the remainder of the day.

(d) Reserve

This is not unused generation. It is generation which is planned to be held in readiness to replace operating generation whenever it becomes unavailable for any reason.

There are many categories of reserve generation.

Installed Reserve equals the peak capability of all the installed generation, minus the peak load.

- Looking to the future, one deals with Forecast Installed Reserve

- Looking to the past, one deals with Actual Installed Reserve

The Actual Reserve equals the peak capability of the generation capable of being operated, minus the peak load. The Actual Reserve is generally smaller than the Installed Reserve, because for most of the time some of the installed generation is incapable of being operated.

The Actual Installed Reserve may have the following components:

- Reserve Unavailable for Operation. This is generating capacity unable to operate fully because it has been forced out of service or limited in its output due to breakdown; or because it has been deliberately taken out of service or operated at partial output in order to enable maintenance to be completed.

- Actual Reserve. This is reserve available for operation. It includes:

  Operating Reserve, which is generation capable of being fully loaded within 5 minutes. It comprises two components:

  i) Spinning Reserve, which is generation operating on the system under governor control at an output less than its maximum output, and which is capable of being further loaded within five minutes.

  ii) Ready Reserve, which is generation not operating but capable of being started and being loaded within 5 minutes.

  Slow Pick-up Reserve, which is generation in addition to the Operating Reserve, and which is capable of producing energy in 5 to 60 minutes. It may comprise two components:

  i) Spinning Reserve, which can be loaded in 5 to 60 minutes.

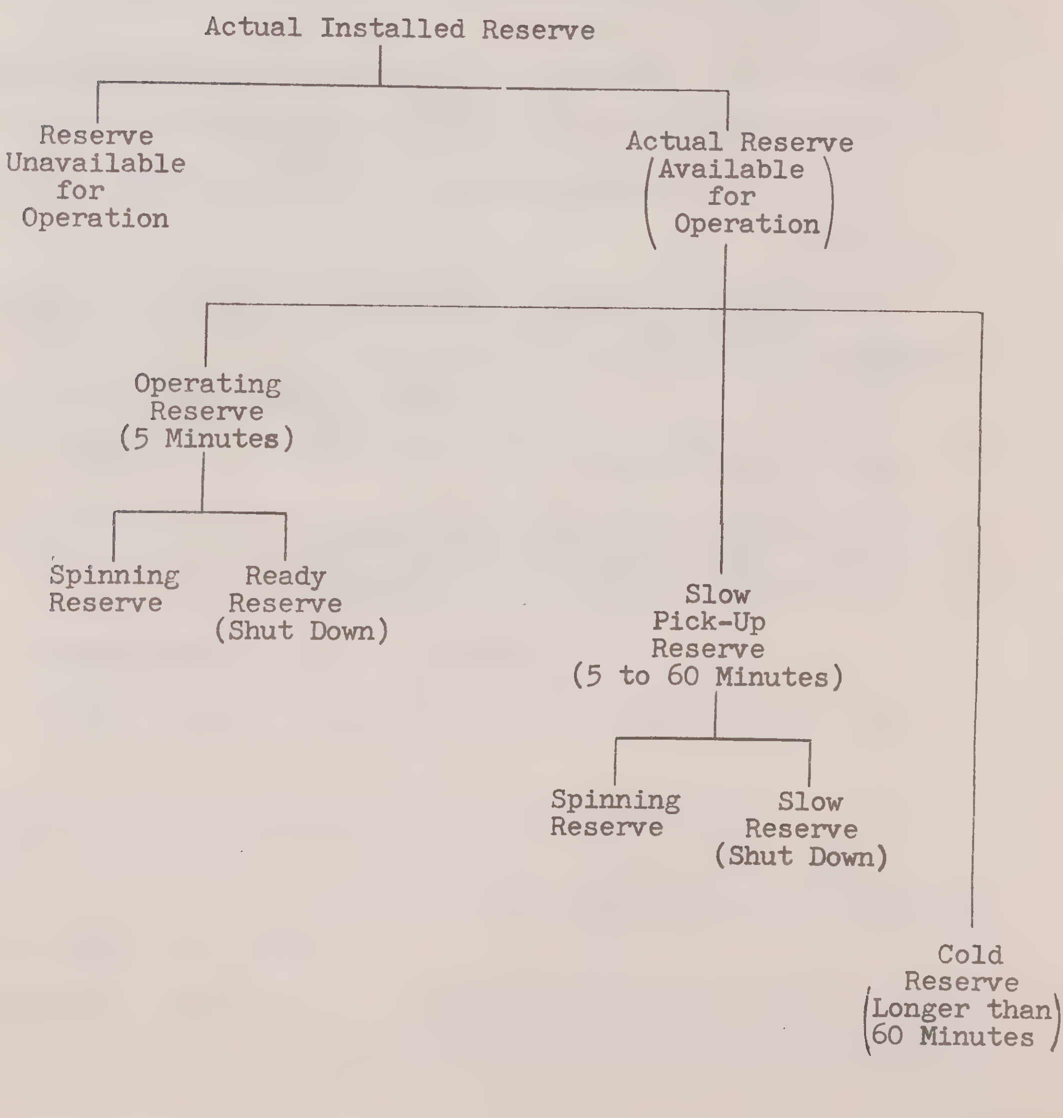
  ii) Slow Reserve, which is generation not

operating but capable of being started
and being loaded within 60 minutes.

Cold Reserve, which is generation not operating and requiring longer than 60 minutes to start and to produce energy.

These reserve categories are summarized below.

COMPARISON OF GENERATING RESERVES



It is desirable that the reserve generation be capable of being operated fully for long periods of time. In this way, it can provide both the peak and energy output needed to replace base load and intermediate load generation that becomes unavailable.

However, much of Ontario Hydro's reserve hydraulic generation has severe limits on its capability to provide energy back-up. This is due to limitations in water flow and water storage.

Also, some of the reserve thermal generation may be unable to provide long duration energy back-up. This is due to limitations in fuel supply (which may apply to the gas turbines) or due to environmental regulations which may prevent extended operation at some stations.

C. Low Cost of Power Supply Within Environmental Constraints

Achieving this objective requires the striking of an appropriate balance between the availability of capital funds for constructing facilities, and the ensuing costs of capital, operation, maintenance, materials including fuels, and social costs.

In striking this balance, the decision process includes consideration of some social costs. These are the specific expenditures which Ontario Hydro makes to meet explicit government regulations where they exist and to meet its own perception of other environmental limitations. Although it is difficult to quantify all social costs and social benefits incurred externally from Ontario Hydro, an increasing effort is being made to do so.

In recent years, Ontario Hydro has included an estimate of social costs in the evaluation of the sales of surplus interruptible power to United States utilities.

5.4 Planning for Reliability of Electric Production from the Future Generating System

A. Factors Affecting Generating System Reliability

The reliability of any generating system hinges on many factors, which can be grouped under four main headings:

(a) Reliability of Equipment and Structures

This is related to the inherent mechanical, electrical, and structural reliability of each generating unit. It reflects the decisions made in the design, manufacture and construction of a unit, and the capability of the actual equipment and materials to perform the operating duty actually imposed on them. If a generating unit is operated in a mode different than that for which it was designed, or if actual operating conditions (type of fuel, weather phenomena, etc) are different than assumed in the design, the reliability of the unit may be affected.

(b) Capability of Staff and Support Services

The reliability of a generating unit will be affected by the availability and competence of Ontario Hydro's staff, the extent of its internal maintenance facilities, the assistance available from consultants and from manufacturers for the repair and improvement of equipment, the availability of adequate funds and time to repair defective equipment, etc.

(c) Availability of Critical Operating Supplies

These include such items as nuclear fuel, coal, natural gas, oil, heavy water, lubricating oils, spare parts, etc. Fuel supply reliability is discussed in Section 6.2. Heavy water supply reliability is discussed in Section 6.3.

(d) Unpredictable External Factors

These include strikes, extreme natural phenomena, malicious damage, changes in government regulations, etc.

B. Selection of the Appropriate Level of Generating System Reliability

As noted in Section 5.3, reserve generation must be provided and kept in readiness to replace any operating generating unit when it becomes unavailable.

Regardless of the amount of reserve generation, there is always some chance, however small, that the available generation cannot completely supply the load. Thus, reliability is a matter of degree, not of absolutes.

To the extent possible, Ontario Hydro's aim is to design, construct, operate and maintain its generating system so as to provide an overall balance between the total cost and the reliability of its generating system.

It is not yet possible to compute the best overall balance between cost and reliability, for two reasons:

i) The degree of reliability of supply of power and energy from the generating system involves many factors, including the reliability of supply of primary energy and other materials (water, coal, gas, oil, uranium, etc), the physical reliability of the generating system, the performance of the operating staff, etc. No means yet exist to compute within reasonable error the degree of reliability of all the individual factors, and hence the reliability of supply of power and energy from the generating system.

ii) The value of various degrees of reliability of supply of power and energy to the users is not yet known.

Methods of improving the assessment of these factors and their effect upon overall generating system reliability are under continuing study within Ontario Hydro and among other interested groups.

Regardless of the improvements that are made in these assessments, judgements will always be required on the degree to which money will be spent to provide reliability of the supply of primary energy, of the generating facilities, of operating and maintenance staff, etc.

Ontario Hydro makes judgements on the question of reliability of supply of primary energy and other materials. A description of its practices is given in Section 6.2.

Ontario Hydro uses a method of probability analysis which has wide acceptance among North American electric utilities as a guide to assessing its requirements for reserve generating capacity, for improving the reliability of generation equipment, and for changing its operating and maintenance practices. A description of the available methods of analysis and Ontario Hydro's practices respecting generating reserves is given in Appendix 5-A.

These probability analyses show that the actual level of reliability of a generating system depends primarily on the number, size, and forced outage rates of the generating units and on the characteristics of the patterns of electricity consumption. In order to provide the same degree of reliability, systems having different generating units may require different percentage reserves. Thus, the fundamental yardstick in comparing systems is their level of reliability, and not their percentage reserves.

Ontario Hydro believes that the planned level of reliability for its future generating system is about the same as that of other large North American utilities.

Based on the probability studies and cost analyses, which will be discussed in Section 6.1, it is Ontario Hydro's current judgement that generating units which Ontario Hydro should develop up to 1985 should be in the range of 500 MW to 750/850 MW. On this basis, and if there are no constraints on capital, its reserve generating capacity in the 1980's should be in the range of 25% to 30% of the firm load. Its judgement also is that future nuclear capacity should be developed as rapidly as feasible in order to provide for a reliable energy supply.

If Ontario Hydro were to use much smaller generating units than the 500 MW and 750/850 MW units it is proposing, the percentage reserves could be smaller than 25%. This would mean that less capacity would have to be installed. However, the total cost of power would be higher. This is because the capital, operating, and maintenance costs per kilowatt of the smaller units would be sufficiently greater than those of the larger units to more than offset the reduction in installed capacity.

Thus, the significant factor is the total cost of a generating system, including the reserve capacity needed for the planned reliability. The percentage reserves by themselves are not relevant to the assessment of either reliability or economy.

C. The Effects of Reducing the Level of Reserve Generating Capacity

Reducing Ontario Hydro's percentage reserves would not result in a proportional reduction in the cost of power. This is because the cost of power includes, among others, the following three components:

(a) Costs arising due to the fixed charges on generating capacity and its associated transmission

The deletion of specific generating and transmission facilities in order to achieve the reduction in percent reserves will reduce these costs. The percent reduction in cost may be greater or less than the percent reduction in capacity, depending on whether the cost per kilowatt of the deleted capacity is greater or less than the average cost of capacity included in the total cost of power.

(b) Costs arising due to the variable charges associated with producing energy to supply the load

Reducing the reserve does not reduce the load, i.e., the consumption of electricity. The variable charges of supplying the load will not decrease, and in fact may

increase as a result of deleting specific generating and transmission facilities. For example, deleting a new nuclear station will increase the use of higher cost fossil fuels, or deleting a high efficiency fossil-fuelled station may necessitate increased consumption of fossil fuels at a lower efficiency station.

(c) Net profit from export sales outside Ontario

There are times when Ontario Hydro does not need to operate all of its available generation to supply the load in Ontario. At such times, if there is a market for it in the neighbouring utilities, Ontario may use part of the actual reserve to sell power and/or energy to them. This results in a net profit to Ontario, which is used to reduce the cost of power in Ontario. If reserve generation is reduced, the opportunities to make profitable export sales are reduced and the reductions in cost of power due to such sales are also reduced.

Ontario Hydro's experience is that the effect on the estimated future cost of power from reducing the amount of reserve depends upon the assumption made with respect to future prices and upon the particular changes which are made in the development program in order to reduce the reserve requirement.

A study made in 1973 indicated that a particular reserve reduction of about 5% reduced the estimated long-run cost of power by roughly 2%, assuming no change in export sales; but this illustration should not be considered a general guideline, for the reasons noted in the preceding paragraph.

Reserve reductions produce a smaller change than is commonly assumed in the total requirements for the new generation site and transmission rights of way. The main thrust for developing new generating facilities arises not because of the size of the reserve, but because of the rate of growth of the load.

For example, if load is growing at 7% per annum, a 7% reduction in reserve, say from 25% to 18% of the load, is equivalent to one year's growth in load. The effect is simply to defer the installation of new generation and its associated transmission by one year, year by year into the future. Therefore, reserve reductions produce little change in the total requirements for new generating station sites and transmission rights of way.

Accordingly, one should use caution when considering a reduction in reserves. The peak power supply reliability will decrease rapidly, but the reduction in estimated cost of power and the effect on the long range requirements for new generating sites and transmission rights of way will be minor. If the reduction in reserve is the result of deferring development of nuclear capacity, there may be a substantial decrease in the reliability of supplying energy and a substantial increase in the consumption and total cost of fossil fuel. Reducing the reserve

may also decrease Ontario Hydro's ability to meet environmental constraints.

5.5 Operation of the Actual Generating System to Meet Daily Load Patterns

Regardless of the factors that went into its planning, the actual system that exists on any day is operated in accordance with the following principles:

(a) The factors affecting operation have the following priorities, in the order from highest to lowest:

i) Safety to the public and to Ontario Hydro employees.

ii) Operation to conform with Environmental Constraints.

iii) Reliability of supply to customers.

iv) Lowest cost of energy production. Effectively, this is tantamount to the lowest total cost of fossil and nuclear fuel consumption.

(b) Energy production cost considerations lead to specific "merit" order operation of generation with the generating units having lowest production cost being used before higher cost generating units.

(c) "Merit" order of operation is modified as necessary to maintain area supply reliability or satisfy environmental constraints. Thus, some generating units are given a higher priority for energy production than their merit order implies.

(d) The total generation scheduled to be available for operation in a given day must equal the forecast peak load plus an operating reserve. The latter must be held in readiness to replace generating units which might fail or to provide for the possibility of the actual load being greater than forecast.

5.6 The Existing Generating System

For a long period in the past, new fossil-steam generating units tended to be of lower cost to operate than older units. Hence they began their operating life in the base load mode. Later, as even less costly units were developed, these in turn took over the base load mode and the older units tended to be shifted successively into the intermediate load, peak load, or reserve modes.

In recent years, the possibility of further improvements in the operating cost of fossil-fuelled units has declined. In addition, nuclear units have had some limitations in operating

flexibility. As a result, in recent years there has been a tendency to develop generation to operate throughout its whole life in one of the four operating modes described in Section 5.3; e.g., recently installed base load units may be expected to operate in the base load mode throughout their life, and recent combustion turbines may be expected to operate primarily in the reserve mode.

The past development of the Ontario Hydro generating system has been planned with due consideration to these factors. Planning has also been affected by the extent of hydroelectric developments, which have limitations in energy production due to the limitations in water supplies. The composition of the Ontario Hydro East System generating resources in-service by January 1, 1976 is as follows:

		January Dependable Peak Resources	
		In MW	In %
Hydraulic		5574	30
Thermal	Nuclear	2284	13
	Fossil-Steam	8816	48
	Gas Turbines	388	2
Purchases		1196	7
Total		18258	100%

Appendix 5-B illustrates some of the seasonal peak and energy characteristics of these generating resources and those of the West System. It also indicates the modes in which this generation can be expected to operate in 1976.

6.0 GENERATION

Summary

This section discusses the alternative types of generation and fuels. It compares them from the point of view of cost and operating characteristics, and reaches a general conclusion on the probable nature of the future development of generating sources for the period up to 1995. It also discusses the supply and demand for heavy water (D_2O), the subject of thermal generating station sites and the effects of generating stations on the environment.

It is Ontario Hydro's position that in the period up to 1995:

(a) the major portion of the base load electric generation in Ontario can be provided most economically and most reliably by the installation of CANDU nuclear stations. Reserves and supplies of uranium in Canada should be adequate for such stations constructed beyond 1990, provided exploration and development are actively pursued over the next 10 years and export limitations are ensured.

(b) primary fuel reliance should be placed on uranium, provided the related capital requirements can be met. Any large additional consumption of fossil fuels should be in coal, although this should be limited because of concerns related to supply, cost and air quality. Further major commitments to use of oil and gas should be avoided, if possible, due to their relative scarcity and cost;

(c) most new nuclear and fossil-steam generating stations should be large central power stations located adjacent to major bodies of water. However, smaller power stations with multipurposes such as electric generation, steam production for district heating or industrial purposes, and refuse burning may become economic in certain locations; some of these may be located inland;

(d) none of the new technological alternatives currently being discussed in the public domain (solar power, wind power, geothermal power, fusion, etc) are likely to have been sufficiently developed as economic and reliable generating sources to form a significant component of the Ontario power system;

Wind power may have applications for electricity generation in remote communities. Solar energy will be used primarily for heating rather than electricity generation.

(e) to meet the growth in needs for reserve, peak load, and intermediate load generating capacity, and to replace fossil-steam generating units which have come to the end of their useful life, different combinations of further

hydraulic and fossil-steam capacity and energy storage schemes may be developed;

(f) the only major sources of hydraulic energy remaining for development in the province are on rivers emptying into James Bay and Hudson Bay. One possibility is the development of the Albany River. This could involve 15 power dams and several major river diversions. The development of this and other hydraulic projects is likely to be affected by economic, social, and environmental considerations, and provincial policy with respect to the development of renewable resources;

(g) Ontario Hydro should continue to participate with Atomic Energy of Canada in programs for development of advanced fuel cycles involving thorium and recycled plutonium. This will permit the gradual replacement of uranium in the existing and future CANDU nuclear plants. This greatly extends the energy resources available to the province. It will ensure continued utilization and return on investment in the CANDU system;

(h) power and energy purchases from neighbouring utilities should continue to be investigated, and arranged when they are economic or required to enable the electric load in Ontario to be met.

(i) As it may not be possible or desirable to install additional heavy water production capacity at the Bruce Nuclear Power Development subsequent to BHWP-A, B, C and D, it would be desirable and prudent for Ontario to make provision for heavy water production at another site.

6.1 ALTERNATIVE TYPES OF GENERATION

CONTENTS

6.1 Alternative Types of Generation (cont'd)

CONTENTS

DIAGRAMS

FIGURES (Bound in Volume 2)

6.1 ALTERNATIVE TYPES OF GENERATION

A. Summary

This section discusses the alternative types of electric generation. For the types which are expected to be commercially available up to 1995, it provides estimates of operating characteristics, reliability, and cost.

B. General Remarks

The basic sources of electric generation are:

- thermal (using fossil and other combustible fuels, and nuclear energy)
- hydraulic
- Geothermal
- chemical (fuel cell)
- wind
- solar

These basic sources may usefully be combined with energy storage systems, such as:

- hydraulic
- heat storage
- air storage
- chemical storage
- mechanical storage, etc

This section compares alternative methods of generation using these basic sources of energy, and certain energy storage schemes.

An electric utility selects a mixture of different types of generation in order to meet a wide-ranging and complex set of requirements, including the safety, environmental, reliability, operating flexibility, and cost aspects.

The alternative types of power sources that can be reasonably considered as reliable additions to the Ontario Hydro system up to 1995 are shown in Figure 6.1-1.

The figure indicates for each alternative the possible annual capacity factors of operation, and the range of capacity factors most likely to be economic. The price of purchased power determines whether it is economic at any capacity factor.

Hydraulic stations can operate over a wide range of annual capacity factor from about 0% to near 100% depending on the availability of water and the generating capacity installed. Some stations may be designed to produce base load energy. Others may be designed to store water in resevoirs and generate only a few hours per day at peak output.

The nuclear stations being installed at present are designed to operate primarily on base load. They are high capital but low fuel cost installations.

Fossil-steam stations may operate over a wide range of capacity factor from year to year, depending on variations in the system load and the availability of more economic resources. These stations are generally low capital but high fuel cost installations.

Ontario Hydro does not have significant indigenous reserves of fossil fuels. Much of the energy consumed in Ontario is imported, is in limited supply, and is rapidly increasing in cost. Ontario must face the dilemma that nuclear generation, the type of generation requiring least import of fuel and leading to the lowest overall cost of base load energy requires the largest initial capital investment.

The remainder of this section gives brief descriptions of the alternatives and summarizes their basic characteristics, including their capital and operating costs and their reliability.

C. Steam Power Stations

(a) Description of Fossil-Steam Stations

A fossil-steam generating station is a plant for converting the energy in fossil fuel to electric enery. The conversion is achieved by burning the fuel to produce steam, and using the steam to rotate a steam turbine driving an electric generator. The electricity from the generator terminals is fed into the electric system through appropriate transformers and switches.

The fuel (gas, oil or coal) is fed into the furnace of the steam boiler where it is burned. Natural gas is brought into a generating station by a branch line from a local gas pipeline. It does not require storage of any kind on the station; and it is clean fuel, producing very little ash and containing very little sulphur. Oil, usually residual oil, can be brought to the station by pipeline, boat or train and requires storage facilities at the station, generally of an extensive nature.

Coal is delivered by boat or train and also requires considerable storage space and extensive handling, crushing and pulverizing facilities in order to prepare it for firing in the furnace.

The boiler or more accurately, steam generator, is essentially a huge furnace lined with tubes carrying water and steam. Water is fed into these tubes and steam is collected at the top of the furnace. The steam is further heated to a higher temperature (superheated) and led to the steam turbine through large pipes. The steam is expanded through the turbine where it gives up energy to rotate the electric generator and is then exhausted at low pressure to a condenser. The condenser is a device for returning the steam to the liquid state so that it may be pumped back to the boiler for heating in a continuous cycle. The condenser is operated at the lowest feasible temperature in order to permit the extraction of the maximum amount of energy from the steam. The low condenser temperatures are normally achieved by using cold lake or river water for cooling.

Burning of fuel in the furnace, in addition to producing the heat to raise steam as mentioned above, also produces ash and hot gases. The heavier ash which is termed bottom ash falls to the bottom of the furnace and is removed by a hydraulic transport system. The lighter ash which stays suspended in the gas is termed fly ash and most of this is collected in large and highly efficient electrostatic precipitators. Tall chimneys are used to release the gases and remaining fly ash to the atmosphere at a height, thus ensuring adequate dispersion. Diagram A is a simplified cross-section of a coal-fired generating station showing the flows of coal, flue gas, cooling water and steam.

(b) Description of Nuclear Stations

The terms nuclear energy and atomic energy are often used interchangeably. Both refer to energy liberated by a nuclear reaction (fission or fusion) or by radioactive decay.

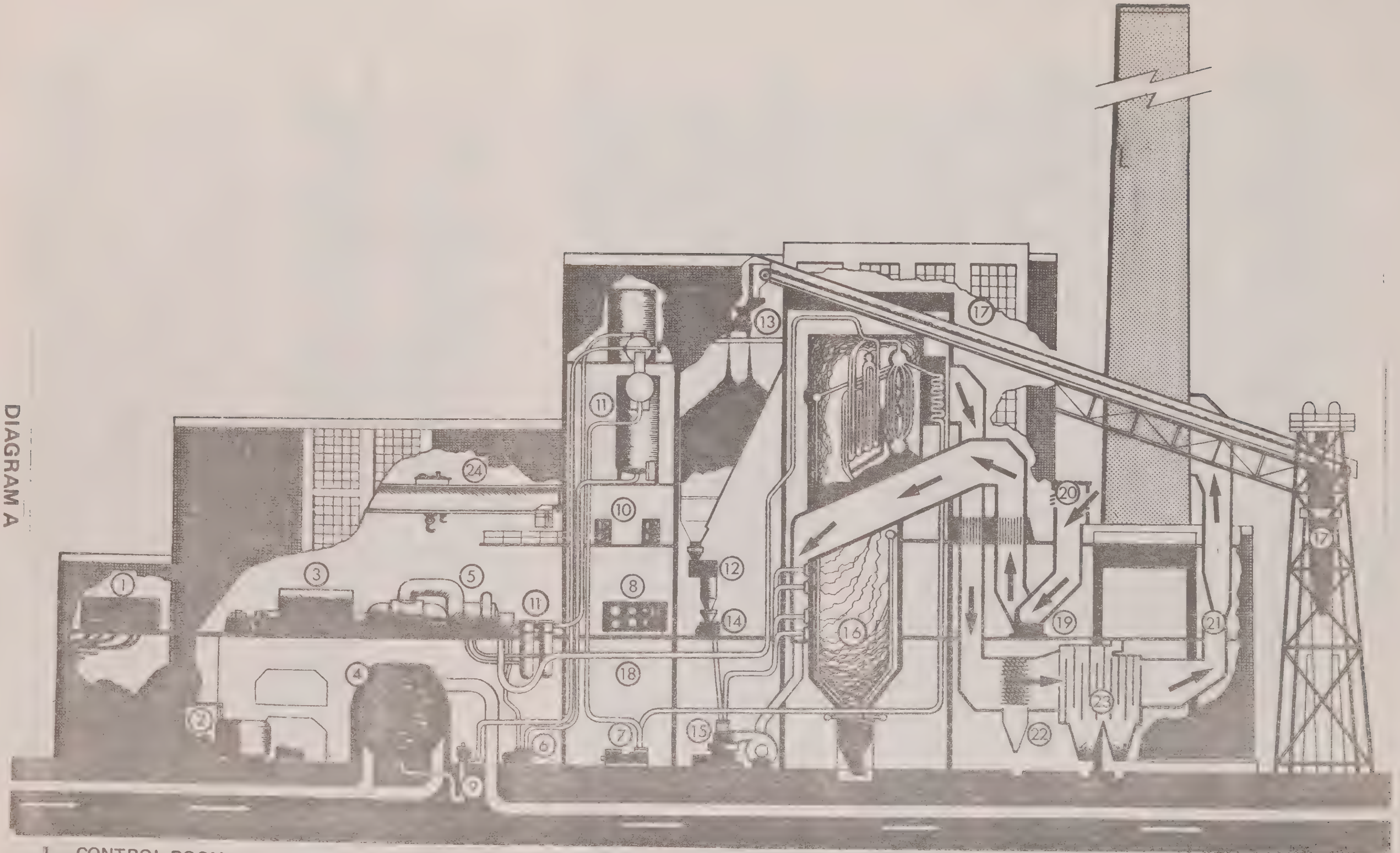
In a nuclear power station, heat is produced by splitting atoms in uranium fuel (fission). This heat is transferred to the boiler where it produces steam. The steam is led to a steam turbine, and from this point on, a nuclear station is similar to a fossil-steam station.

The Canadian designed and built reactor has three specific features which distinguish it from other types:

- it uses natural uranium fuel
- it uses heavy water as the moderator
- it is a pressure tube reactor

The system is known as CANDU, which is derived from Canada, Deuterium and Uranium, signifying that it is a Canadian concept,

DIAGRAM A



1. CONTROL ROOM
2. STATION SERVICE TRANSFORMER
3. ELECTRIC GENERATOR
4. CONDENSER
5. TURBINE
6. BOOSTER PUMP
7. FEED PUMP
8. STEAM GENERATOR CONTROL
9. CONDENSATE PUMP
10. STATION SERVICE SWITCHBOARD
11. HEATERS
12. COAL FEEDER
13. TRIPPER
14. SCALES
15. PULVERIZER
16. STEAM-GENERATOR
17. COAL CONVEYOR
18. STEAM LINE
19. FORCED DRAFT FAN
20. AIR INTAKE
21. INDUCED DRAFT FAN
22. MECHANICAL DUST COLLECTOR
23. ELECTROSTATIC PRECIPITATOR
24. CRANE

HOW A STEAM GENERATING STATION WORKS

uses deuterium (heavy water) as the moderator and that the fuel is natural uranium.

The heart of the CANDU reactor is a large tank called a calandria. A large number of pressure tubes pass through the calandria. Inserted inside these tubes are metal assemblies, or bundles containing natural uranium fuel pellets.

The calandria contains heavy water used as a moderator to sustain the chain reaction of splitting atoms in the uranium fuel. The heat produced by splitting the uranium atoms is transferred to the coolant which is pumped through the tubes under pressure. The coolant is then passed through boilers where heat is extracted to convert ordinary water into steam to rotate the turbine, which in turn drives the generator and produces electricity.

It is the combination of pressure tubes to contain fuel bundles and coolant in the calandria, the heavy water moderator, and the natural uranium fuel that characterize the Canadian reactor.

The use of pressure tubes gives flexibility to the design of the reactor in that an increase of power may be obtained by increasing the size of the calandria and adding more tubes. Another advantage of the pressure tube design is the ability to refuel without shutting down the reactor. This contributes to efficient use of the fuel in the reactor and eliminates the shutdown time necessary to refuel other types of reactors.

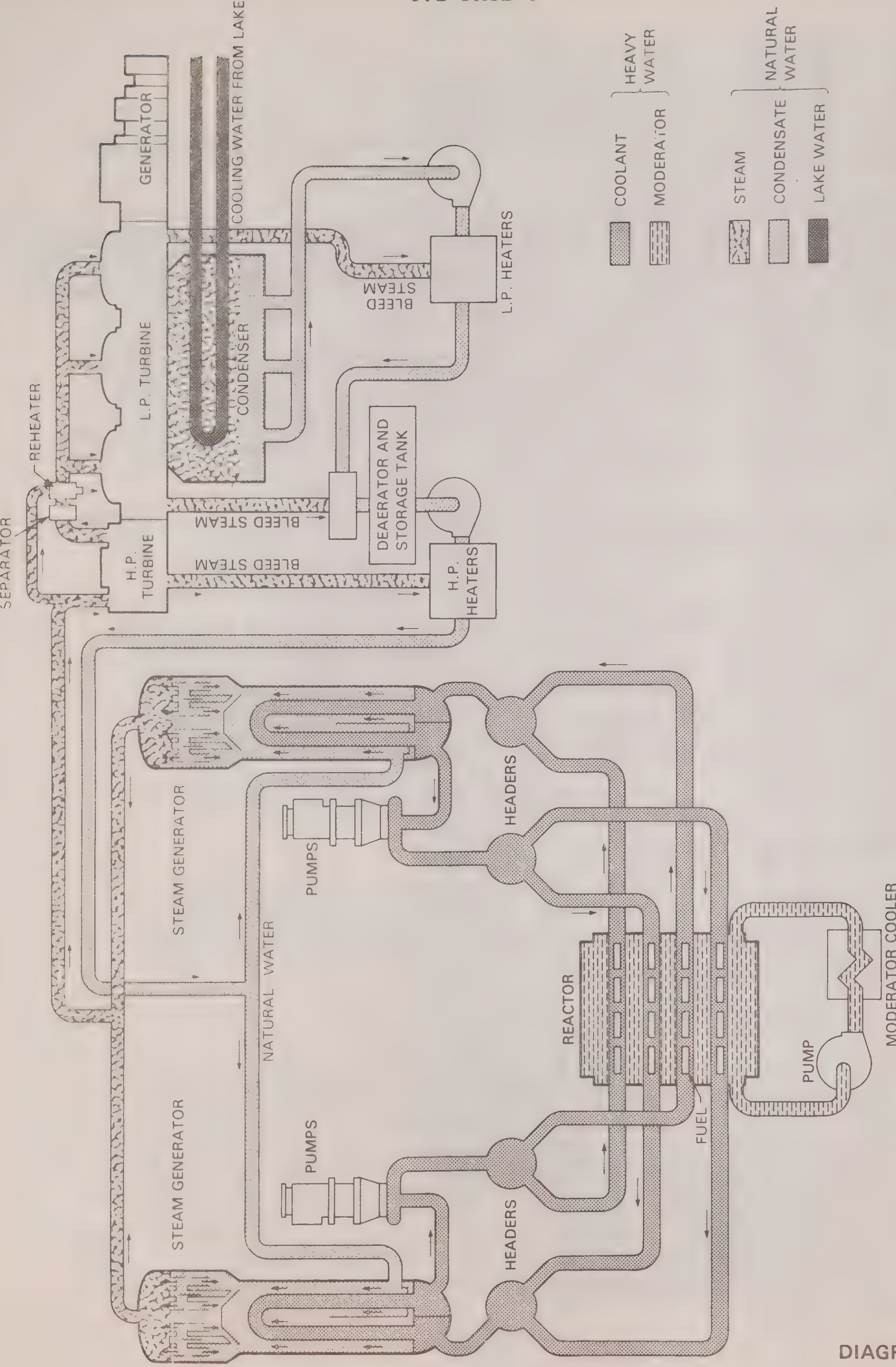
Diagram B shows a simplified CANDU station Flow Diagram.

(c) <u>Steam Turbine Cycles</u>

Many aspects of both the fossil-steam and nuclear-steam generating systems are similar. However, they have some important differences in both the process and its hardware. Both generating systems use the steam turbine cycle, whose important features are discussed below.

<u>Development of the Steam Turbine Cycle</u>

The development of the steam turbine cycle, like that of any other process, is inseparable from the development of the hardware which enables its operation. Because the hardware is large, costly, complex and requires years to build, little development takes place on small laboratory models. Instead, modest, well-engineered changes are made to each new series of equipment sold, and the benefits of these changes are verified by test after the units come into service. Any limitations that result from engineered changes may have to be borne by the unit throughout its entire life of 30 or more years. Therefore, development of the hardware is a slow and deliberate process.



CANDU REACTOR–SIMPLIFIED STATION FLOW DIAGRAM

DIAGRAM B

The fossil-steam cycle and its hardware have developed over the past 70 years. At present, it has reached a high degree of development in terms of complexity, efficiency, reliability and performance. Some of the lessons learned from the fossil-steam cycle were very helpful during application of the steam turbine cycle to nuclear power generation. Thus the nuclear steam generation system has had an excellent technical base on which to begin. From that base there has been considerable progress over the past 15 years, much of it in the area of increased unit sizes and reliability.

The Steam Cycle

The chief objective of the steam cycle is to convert as much heat as possible to shaft power at the generator, and in turn to electricity.

The efficiency of the steam turbine cycle is dependent upon a number of factors. The most important are:

- The difference between the temperature and pressure of steam admitted to the turbine and that of steam exhausted from it.
- The number of times that the steam is removed from the turbine, reheated in the boiler, and readmitted to the turbine to continue its expansion.
- The number of stages at which water enroute to the boiler is heated, by using partially spent steam drawn from the turbine.

Each of these points is discussed below:

(i) Steam Temperature and Pressure

The greater the difference between the inlet and exhaust steam conditions of temperature and pressure, the more efficient the steam cycle. Since the exhaust conditions are determined by the lowest available temperature of cooling water, little or no improvement in efficiency can be achieved with the exhaust steam. Therefore, the opportunities for improvement of efficiency must be sought by raising the temperature and pressure of the inlet steam.

The inlet steam to a steam turbine can be classified by the following terms:

Sub-critical Wet Steam

A boiler operating at "sub-critical pressures" is similar to a kitchen kettle, although it operates at much higher temperatures and pressures. The boiler drum contains water from which steam vaporizes at a temperature of about 500°F.

This "saturated" steam is piped directly to the turbine and expands to rotate the bladed wheels. In doing so, it cools and this causes water droplets to form in the turbine. Therefore, a turbine using saturated steam is referred to as a "wet-steam turbine". Most nuclear reactor boilers, including CANDU, produce wet-steam and have wet-steam turbines.

Sub-critical Dry Steam

If the saturated steam leaving the boiler drum is passed through an array of tubes and heated, its temperature is raised. The upper limit of this temperature is generally 1000°F; and to avoid equipment damage the boiler must be operated in a way that the steam temperature does not exceed this value by more than a few degrees. To appreciate this situation, one should note that steam pipes carrying steam at 1000°F are literally red hot. This high temperature steam can be expanded through most of the turbine before it is cooled sufficiently to produce water droplets. Hence such turbines are referred to as "dry-steam turbines". All of Hydro's fossil-steam units operate with dry steam at sub-critical pressures.

Super-critical Dry Steam

By raising the pressure within the boiler drum to a value above 3200 psi, the density of the steam and water becomes identical. Water is converted to steam without any apparent change in its state. Because of this there is no water surface in the boiler. This eliminates the need for a steam drum. The super-critical dry steam is at 1000°F temperature and performs in much the same way in the turbine as sub-critical dry steam. Ontario Hydro does not have any units operating at super-critical steam pressures.

There are major gains in both cycle efficiency and turbine costs by using high temperature dry steam rather than lower temperature wet steam. Marginal advantages to efficiency and boiler and turbine costs result by using super-critical rather than sub-critical pressures. However, other factors offset these advantages in Ontario and this is discussed in Section 6.1 D.

Present water-cooled nuclear reactor technology limits their use to wet-steam turbines.

(ii) Reheating of Steam

As noted above, steam cools as it expands through the turbine. If it is removed after partial expansion and reheated in the boiler to the maximum temperature again, and then returned to the turbine to complete its expansion, there is a marked gain in efficiency. A second reheating process provides a smaller gain. Ontario Hydro uses only single stage reheating in its fossil-steam units. It has been unable to justify a second

stage because of the increased capital costs and reduced reliability that results.

Reheating has the added advantage of reducing the detrimental effects of moisture on the exhaust portion of the fossil-steam turbine. For this reason reheating is used with nuclear wet-steam turbines, even though the efficiency gains in this case are negligible.

(iii) Regenerative Boiler Feedwater Heating

The water condensed from turbine exhaust steam has a temperature of 80°F as it leaves the condenser. If this water is fed directly into a fossil-fuelled boiler, a large amount of fuel will be burned to raise its temperature to the boiling point. However, by preheating the water with steam extracted from the turbine, virtually all of the fuel will be used to vaporize the water to steam, and to raise the steam temperature to 1000°F. The steam extracted from the turbine can be used very efficiently since it has already provided some mechanical energy and all of its latent heat can be transferred to the feedwater, rather than being discarded to cooling water. (This is the same principle as that used in combined heat and power systems for district heating.) As a result, cycle efficiency is increased. If the steam is extracted at a number of turbine stages during expansion, further increases in efficiency are achieved.

Ontario Hydro's modern fossil-steam units generally have 7 stages of regenerative feedwater heating. This reduces the fuel used by the boiler by about 35% but it also reduces the unit output by about 20%, since only about two-thirds of the steam is expanded through the entire turbine. The net result is an improvement in efficiency of about 15%. There is a similar improvement in the nuclear-steam cycle efficiency with 5 stages of feedwater heating.

The determination of the optimum number of feed-heating stages is a balance between a number of factors, the most important being the cost of additional equipment and the value of future energy savings.

Other Aspects of the Turbine Cycle

Although efficiency is a major goal, the cycle must also be designed to protect the hardware from excessive temperature changes, moisture erosion, chemical attack, water ingestion, and other incidents during both steady state and non-uniform operation. Thus its proper design, construction and operation is basic to the reliability and maintenance cost of the unit.

(d) Cooling

(i) Ontario Hydro Position on Once-Through Cooling Using Great Lakes Water

Thermal Generating stations, both fossil-fuelled and nuclear, use the waters of the Great Lakes for two main purposes: for the production of steam for the turbine, and for cooling and condensing steam at low temperature and pressure and the removal of this reject heat from the station. The first use requires a very small amount of water, normally held in a closed circuit. The second use requires large amounts of cool water to efficiently remove between 50 and 70 percent of all the heat produced at a generating station and to dispose of this very low grade heat to the ultimate heat sink, the atmosphere.

Ontario Hydro now has approximately 13,000 MW of thermal plant (fossil and nuclear) in operation, 8,700 MW under construction and another 7,200 MW expected to be approved for construction in the near future, all using Great Lakes water for cooling. All operating and committed stations and those planned for commitment in the near future utilize a shoreline surface discharge of warm water. The intakes for the early stations were at the surface near the shoreline, however, for all recent projects off-shore bottom intakes are used.

The withdrawal from and the return to the lake of the cooling water at elevated temperatures has been the subject of extensive discussions between the regulatory agencies and Ontario Hydro, with respect to the possible effects on the ecology of the lake.

Ontario Hydro has been undertaking a broad investigational program, in cooperation with other agencies, involving studies of our once-through cooling systems. We have now compiled a substantial amount of data on the physical and biological effects due to our cooling arrangements and have an extensive continuing investigational program which was also recently expanded to include study of alternative means of cooling.

It is Ontario Hydro's view that restrictions and requirements for changes to this cooling arrangement should be based on factual data resulting from such investigational programs. The possible penalties imposed on the citizens and industries of the Province due to unsupported restrictions which lead to inefficient conversion of heat energy into electricity are very large in both capital cost and energy conversion. There is no wish that other beneficial uses be impaired by utilizing the lakes for cooling purposes. Ontario Hydro recognizes that an expanding population surrounding the Great Lakes depends on these large interconnected bodies of water for their livelihood and pleasure. However, it is believed that the use of the Great Lakes water by electric utilities for efficient cooling purposes represents a legitimate use and a very important

energy resource for the Province of Ontario and that this use is or can be made compatible with, if not enhance, other applications.

Although Ontario Hydro's present cooling systems appear to have no significant detrimental effect on the ecology of the lake or lake bottom in the area of the warm water discharge, Ontario Hydro does not have a fixed position on this arrangement. If investigations show that thermal discharges from thermal-electric stations do cause significant deterioration of the quality of the aquatic environment of the Great Lakes, appropriate changes will be made.

(ii) Heat Rejection Characteristics of Thermal Generating Stations

Nuclear generating stations reject more heat to the cooling water than fossil stations of the same size. For example, a 3400 MW station rejects approximately 24,900 million BTU/hr at the condenser plus 2,900 million BTU/hr at the moderator. With a temperature drop of 20°F across the plant, this would require 2,780,000 USGPM of cooling water. A fossil station of the same size rejects approximately 15,500 million BTU/hr of heat which, with a temperature drop of 20°F across the plant, would require 1,550,000 USGPM of cooling water.

The daily water temperature in the lake varies due to natural causes, without a generating station rejecting heat into it. Diagram C shows a hydrograph for Lake Ontario observed at Pickering during 1970 at depths of 26 feet and 5 feet.

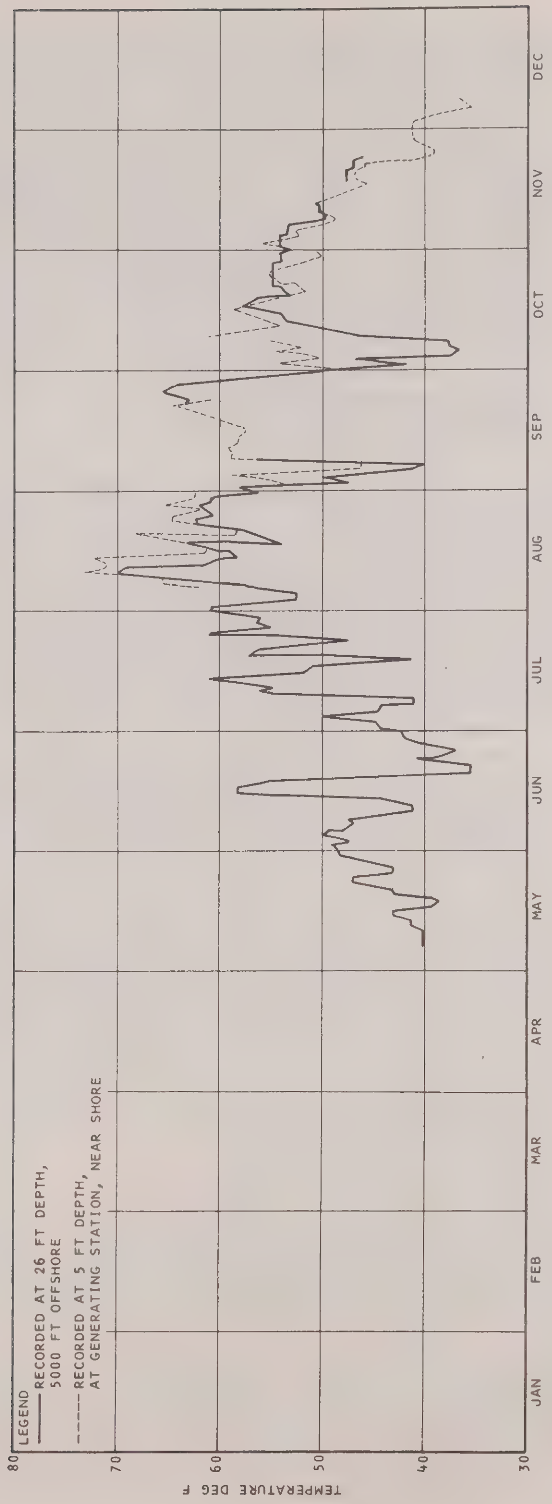
In order to keep the discharge water temperature as well as the temperature rise in the cooling water between plant intake and discharge, within the regulatory agencies' guidelines, Ontario Hydro has been using tempering water in some generating stations. This water is taken direct from the cooler intake and mixed with the discharge to reduce the overall return temperature to the lake.

(iii) Alternative Arrangements for Discarding Low Grade Heat

Offshore Discharge

The broad investigational program undertaken by Ontario Hydro concerning once-through cooling systems includes alternative arrangements for disposal of rejected heat, such as offshore outfalls.

A number of conceptual, economic and biologic investigations of offshore discharge systems have recently been completed for a 3400 MW nuclear generating station. The number of variables involved include the distance offshore, the allowed temperature rise, the type of tunnel, type of diffuser, etc.



LAKE ONTARIO DAILY MEAN TEMPERATURE
AT PICKERING GS 1970

DIAGRAM C

A cooling water system with a shoreline surface discharge similar to that being designed for the Bruce "B" GS will cost 147 million dollars at in-service date (1983). A typical system with an offshore discharge having a concrete-lined tunnel one mile out under the lake with a lake bottom diffuser and having a nominal temperature rise of 20°F would cost approximately 216 million dollars. A similar submerged offshore discharge system without a diffuser would cost 191 million dollars while a two-mile offshore discharge system without a diffuser would cost approximately 232 million dollars. Thus, the additional cost to discharge the warmed water one or two miles further out into the lake is between 44 and 85 million dollars (1983).

With respect to the possible adverse biological influences of the thermal discharge itself, an offshore discharge located beyond the littoral zone is preferred to an onshore discharge. However, with regard to entrainment effects, the shoreline discharges are preferred to offshore discharges. The high-entrainment, submerged discharges are considered to have a higher overall physical impact on the lake than a shoreline surface discharge.

Many years of operating experience have been obtained with the shoreline discharge of cooling water from large thermal generating stations and there is a growing inventory of environmental data which suggests that the arrangement does not cause significant adverse effects on the aquatic environment. The system maximizes the immediate release of heat to the atmosphere from the water surface layer and minimizes the heat input to the lake. The system has a lower time-temperature effect and lower physical effects on entrained organisms than offshore discharge systems. The system does not cause large unbalanced forces on the lake body such as upwelling or currents as may be the case of offshore dispersal systems.

Observations will continue on existing surface discharge arrangements in the Great Lakes. The expanded program concentrating on alternative types of outfalls will continue, including Hydraulic Model Laboratory studies, and experience elsewhere will be reviewed. Mathematical models of plumes from such outfalls will be developed.

Wet Natural Draft Cooling Towers

Cooling towers are structures which draw ambient air through sheets of falling warm cooling water and thus provide a degree of cooling to the water. In the case of wet towers, the water and air come into direct contact and most of the cooling takes place due to evaporation of some of the water. Natural draft cooling towers are the large concrete shells with the hyperbolic profile (this profile is purely for strength). With this type of tower, the air rises up through the falling water due to the pressure differential (chimney effect) created

between the warmed, buoyant air inside the tower and the denser ambient air outside.

Wet natural draft cooling towers are more expensive than smaller wet mechanical draft towers but they are less liable to interfere with the local environment in the way of icing and fogging, etc. However, the appearance of large natural draft towers and the vapor plume emanating from them raises concerns for aesthetics and also for obscuration of sunlight. For a 3400 MW fossil generating station, the probable arrangement would be four 350 ft high cooling towers. For a similarly sized nuclear station four 500 ft towers would be required.

The location of wet natural draft cooling towers in Ontario would be severely limited by the province's low winter temperatures. A band just north of the Lower Great Lakes might be suitable for their operation, but even there, considerable operating difficulty could be expected.

The operation of cooling towers imposes a penalty against a generating station, as in summer, cooling water temperatures become unavoidably high. This, in turn, gives a higher temperature of steam condensation in the condensers which causes a substantial reduction of plant efficiency and output. There is also a considerable increase in pumping power required.

If natural draft cooling towers were installed at a 3400 MW nuclear generating station, the capital cost would be $181,000,000 (1983) more than a comparable once-through system and the capitalized value of 30 years operating costs would amount to a further $276,000,000 (1983). These costs assume that the dissolved solids in the cooling water which do not evaporate can be returned to the natural water bodies from whence they came. The respective costs for a 3400 MW fossil station would be about 60% of the above.

For a 3400 MW nuclear generating station using high quality make-up water, it can be shown that there will be a continuous summertime make-up requirement of about 170 cubic feet per second (CFS). This makeup is required to replace the 100 CFS lost through evaporation and the 70 CFS of flow which is lost in discarding the dissolved solids from the cooling circuit. A similar fossil station will have a make-up requirement of about 60% of the above nuclear station. A perspective of this water requirement is given by comparing it to the flow of the Thames River at London, Ontario. The average river flow is about 500 CFS while the minimum flow is less than 50 CFS. Thus if a river such as this were to be used as a source of makeup, an extensive water storage pond would be required to compensate for low flows.

Cooling Ponds

Cooling ponds are of two types; namely, the still pond and the spray pond.

In a still pond, warm inlet water is introduced at one end of the pond and the cold water supply is drawn from the other end. The water is cooled by evaporation, radiation and convection as air contacts the relatively large surface area of the pond. Heat rejection from the pond depends on local conditions such as wind speed, dew-point temperature, solar radiation and configuration of the cooling path. Cooling ponds have a low heat transfer rate. This results in very large real estate requirements, in the order of one to slightly above two acres per megawatt of installed capacity. For example, a 3400 MW nuclear GS would require approximately 5500-6500 acres of cooling pond surface to dissipate the station rejected heat. The evaporation from a still pond, that is chargeable to a power station, depends upon whether the pond is a natural lake or is constructed specifically for cooling purposes. This is because the additional evaporation from the man-made pond results from both natural causes and from power station cooling. The evaporation from cooling ponds is also highly dependent upon the pond size, the local winds and other atmospheric factors. In general, the additional evaporation caused by the power plant from a natural pond is lower than for either cooling towers or spray ponds, while that from a man-made pond is higher.

The efficiency of a cooling pond is markedly increased by introducing sprays into the system. In a spray pond, surface evaporation is enhanced by spraying the water through nozzles into the air, where it is separated into small droplets, thus exposing a large total surface area to the air and producing an increased rate of evaporation. As a result, spray ponds have the potential of transferring more heat to the atmosphere per unit surface area than still ponds and generally require less than 5% of the total area required for a still pond.

The floating modules, in a spray cooling system, are self-contained units generally consisting of a motor-driven, propeller-type pump which distributes the warm water through various types of diffusers. The spray patterns produced are 40 to 50 ft in diameter and 10 to 20 ft high.

A spray canal is similar to a spray pond except that it is more effective and offers more flexibility in location for large installations. For a canal width of 160 ft, a 3400 MW GS would require a canal length of 30,000 to 40,000 ft, depending on the design conditions (cooling water temperature range, condenser intake temperature, etc.) and on the spray module manufacturer design. A 3400 MW fossil GS would require a canal length of 16,000 to 22,000 ft.

One of the disadvantages of spray cooling is the penalty imposed on the efficiency of the generating station. The cooling water operating temperatures are relatively high compared to once-through cooling, especially during the summer. This, in turn, gives higher steam condensate temperature and pressure in the condenser, and the turbine back pressure is increased accordingly causing a loss in power output and turbine cycle efficiency. The increase in turbine heat rate over once-through cooling could be as high as 10%. Another important loss is the pumping power required for the spray modules, which for a 3400 MW nuclear GS could be as high as 32 MW.

Potential environmental problems related to spray systems include: drift of water droplets and vapour from the spray pond or canal, fog formation and icing. There has not been enough experience with large spray cooling systems, especially in winter, the season of the largest fogging potential. Based upon experience at Dresden Nuclear GS (Commonwealth Edison Co.), it was reported that some light fog (visibilities better than 100 ft) could be expected up to 1000 ft from the spray canal near dawn or on cold winter mornings (temperature less than 10^{o}F). It was also reported that significant drift of water droplets is unlikely to occur at distances greater than 600 ft from a spray canal and that the total volume of drift will not exceed 0.01% of the spray water except during high winds.

Operating problems associated with spray cooling include failure of pump or motor, bearing damage, nozzle plugging and icing on the motors during the winter.

In a spray cooling system, most of the heat is dissipated to the atmosphere by evaporation. The amount of evaporated water for a 3400 MW nuclear GS would be approximately 100 CFS during the summer. Because of this evaporation, the spray cooling system requires blowdown to prevent concentration of dissolved solids. Using high quality make-up water, a 3400 MW nuclear GS would require a blowdown of 70 CFS. To replace the water lost by evaporation and blowdown, the make-up water requirement for the above GS would be 170 CFS. Evaporation, blowdown and make-up water requirements for a similar fossil GS would be 55 to 60% of the above nuclear GS. Again, this can be placed in perspective by comparing it with the flow of the Thames River at London, Ontario which averages about 500 CFS, but is less than 50 CFS at low flow.

The estimated increase in capital cost for installing a spray canal system at a 3400 MW nuclear GS over a once-through cooling system is approximately 102 million dollars (1983), not including real estate costs for the spray canal. The estimated increase in present worth value (1983) for the operating costs of the spray canal, capitalized over 30 years life of the station, is approximately 281 million. The estimated increase in total capital and operating costs of a spray canal system

over a once-through system for a 3400 MW nuclear GS would, therefore, be 383 million dollars. These costs assume that the dissolved solids in the cooling water which do not evaporate can be returned to the natural water bodies from whence they came. The respective cost increases for a similar fossil station would be approximately 60% of the above costs.

(e) Conservation of Energy

(i) Efficiency and Waste Heat

The discharge of large quantities of waste heat from thermal power stations seems irrational to many people, particularly in view of today's predictions of energy shortages. Why can't the heat be used? Why can't the converstion of heat to electricity be more efficient?

These are good questions, and they are asked by many today. A few people associated with the power industry have been asking them for many years, and have made large strides toward improved efficiency and conservation of fuel. Even so, the challenge to do better is more evident today than ever.

It is the purpose of this section to explain the reasons for discharging heat from thermal power stations, to examine the barriers to reducing discarded heat, and to indicate Ontario Hydro's progress in finding beneficial uses for the heat.

The Efficiency of Heat Conversion

In processes which convert energy from one form to another, efficiency is the measure of the useful energy output compared to the total energy input.

Some energy conversion machines have relatively high efficiencies. The list includes waterwheels, pumps, electric motors and electric generators, all of which operate at efficiencies of above 75%. In general, the loss in efficiency of such machines is caused by mechanical, hydraulic or electrical 'friction'. Since these are small losses, high efficiencies can be achieved. The situation is quite different for heat-engines, which convert the heat energy from fuel into mechanical energy.

The losses in efficiency of a heat engine result from the friction losses discussed above and also from limitations imposed by some of the physical laws of heat. One of these laws relates the highest achievable efficiency to the highest and lowest temperatures occurring in the machine. Thus, a CANDU nuclear unit, which must operate with steam between upper and lower temperature limits of 490°F and 80°F, respectively, has a maximum theoretical efficiency of 41%. To achieve this efficiency the unit would have to operate without friction, and be perfect in all other respects. In the real world, the CANDU

unit operates at 30% efficiency which is about 73% of the maximum achievable within the temperature limitations.

Upper and lower temperature limitations on fossil generating units are 1000°F and 80°F and this results in their higher operating efficiency of 38%.

Many improvements have been made in the steam turbine cycle which has raised its efficiency to a level that is generally higher than that of other heat engines, for example, the efficiency of an automobile engine is only about 15%. Even so, there is room for improvement, since at present approximately two thirds of the heat supplied by the fuel must be discarded.

<u>The Steam Turbine Cycle for Power Generation</u>

The conversion of heat energy to mechanical energy requires the use of stationary and rotating mechanical equipment, and a 'working fluid'. A working fluid is a gaseous substance which can be pressurized and heated by fuel to raise its temperature. As the hot, high-pressure gas is passed through an engine, it expands and its temperature and pressure are dissipated. The expansion causes the engine to rotate.

The spent working fluid is removed at the point where it is 'exhausted' and is incapable of further expansion. In jet engines, gas turbines and auto engines, the spent fluid is discharged directly to the atmosphere through the exhaust pipe, while in the old steam locomotive it was released through the stack.

In the steam turbine cycle used for power generation, steam is the working fluid and it is continuously recycled. This recycling increases efficiency, reduces waste heat and cuts plant capital and operating costs. It also eliminates the environmental problems of steam releases to the atmosphere, so evident in the days of the steam locomotive.

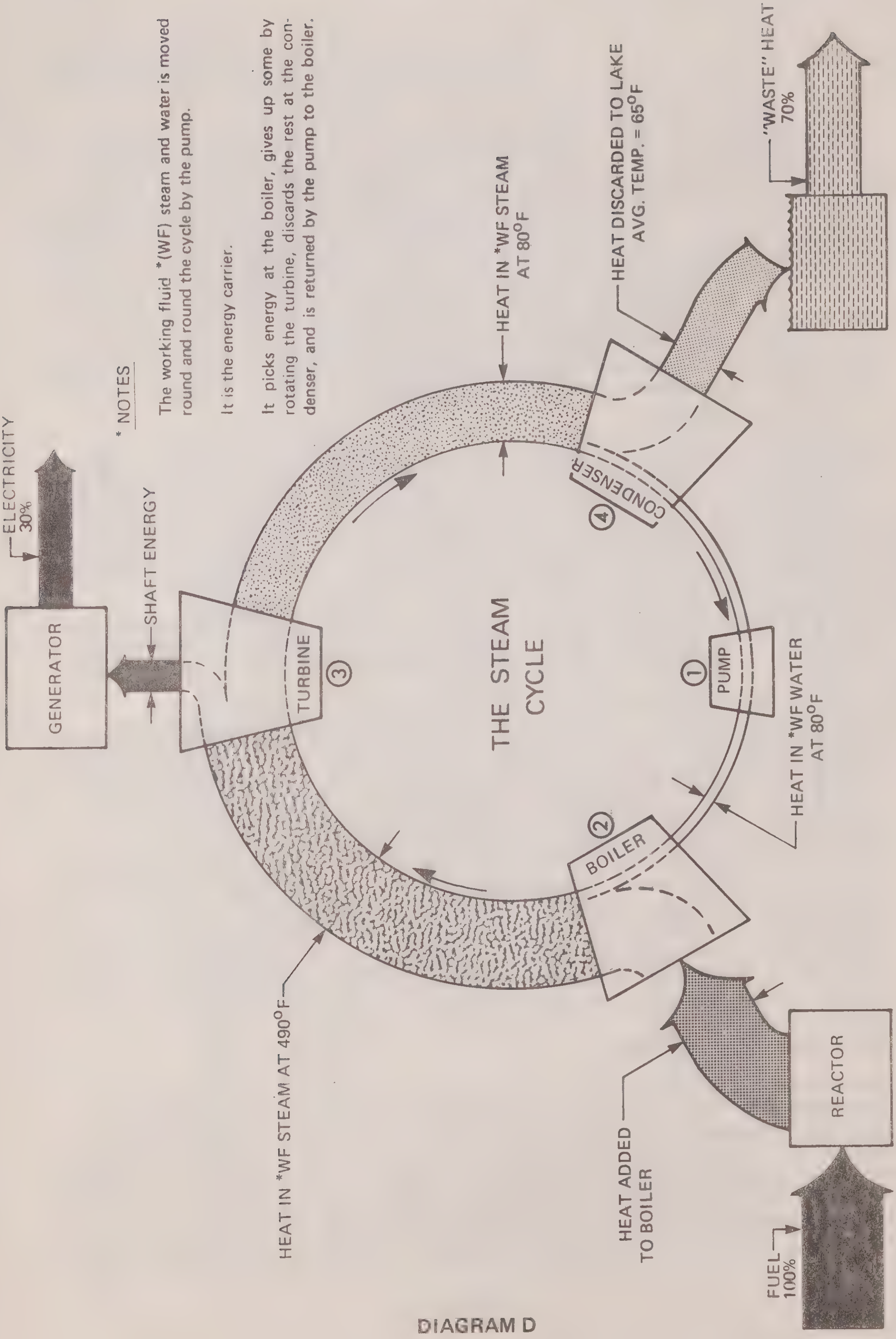
Diagram D shows the progress of the working fluid through a simplified version of a nuclear steam cycle. The cycle has four main components.

1. The pump - which pumps water from the condenser into the boiler.

2. The boiler - which vaporizes the water to steam, using heat from the reactor.

3. The turbine - which is rotated by the expanding steam and which in turn rotates the generator to produce electricity.

4. The condenser- which condenses the spent steam on metal surfaces that are cooled by lake



* NOTES

The working fluid *(WF) steam and water is moved round and round the cycle by the pump.

It is the energy carrier.

It picks energy at the boiler, gives up some by rotating the turbine, discards the rest at the condenser, and is returned by the pump to the boiler.

DIAGRAM D

water, and collects the water thus condensed and returns it to the pump.

It is interesting to note that the working fluid is continuously moving about this cycle. Each time an element of working fluid passes through the boiler it picks up heat energy. It later gives up part of this energy at the turbine for conversion to electricity, and transfers the remaining heat energy to lake water in the condenser. During these important functions the element of working fluid is in the form of steam. Only about 10 minutes is needed for it to complete the cycle, and it is in the high energy steam state for about 10 seconds of that time. So, the name 'working fluid' is well deserved, for each element of fluid moves around the cycle several times an hour, for days and months at a time. Each time, it changes from water to steam and back again, and takes on energy and gives it up again.

Now let us follow one pound of water as it moves about the cycle shown in Diagram E. The pound of water, which almost fills a pint bottle, is first pumped into the boiler at high pressure and a temperature of 80^{o}F. Once inside the boiler, its temperature is raised to 490^{o}F and it begins to boil. About 400 heat units (BTUs) of 'sensible' heat are needed to do this. A further 740 BTUs of 'latent' heat are added to vaporize all of the water to steam. Summing these quantities, the total heat added in the boiler to the pound of working fluid is 1140 BTUs. These quantities are shown on Diagram E.

After leaving the boiler, the steam expands through the turbine, rotating it and the generator to produce electricity. The 'exhausted' steam leaving the turbine enters a condenser designed to operate at a high vacuum. This vacuum literally sucks the steam through the last stages of the turbine and extracts additional power. The steam exhausts into the condenser at the boiling point related to the vacuum namely 80^{o}F. Virtually all of the 400 BTUs of sensible heat added in the boiler have been converted to electric energy. The remaining 740 BTUs are held in the exhaust steam in the form of latent heat. (This is a simplification, but conveys the basic principle). This large quantity of energy is, however, only available at the low temperature of 80^{o}F. Indeed, the exhaust steam is no warmer than the water in a swimming pool.

<u>The Expansion Dilemma</u>

Throughout the process so far, there has been a continuous increase in the volume of the working fluid until, at the turbine exhaust, it occupies 25,000 times the space it did at entry to the boiler, as shown in Diagram F. The pint of water has now expanded to a volume that would fill a small room with steam. This could be called the 'expansion dilemma'. For while expansion is a basic requirement for the operation of the turbine, the recycling of this huge volume of expanded steam

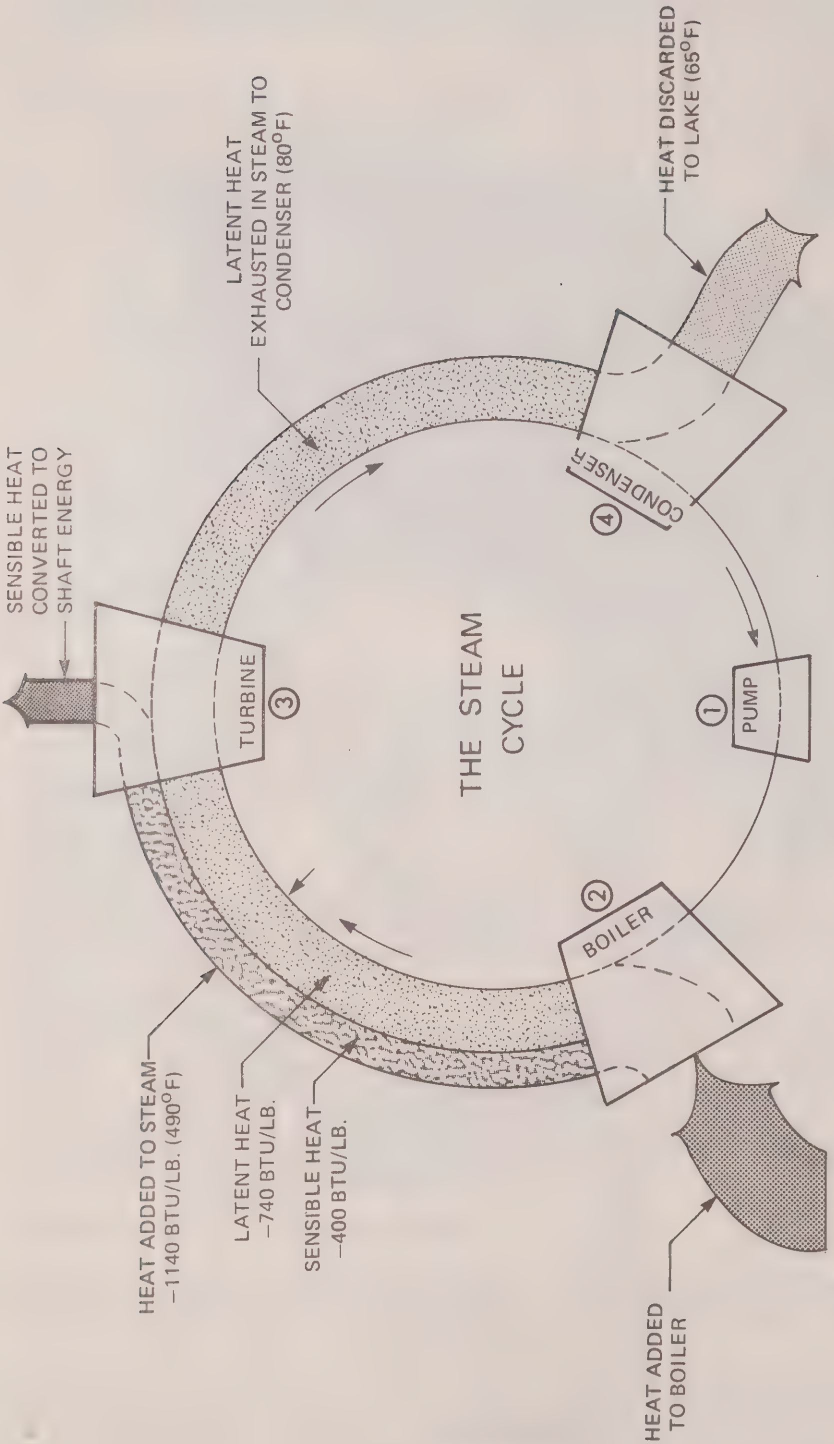


DIAGRAM OF A SIMPLIFIED CANDU STEAM CYCLE SHOWING HEAT ADDED, CONVERTED AND DISCARDED

DIAGRAM E

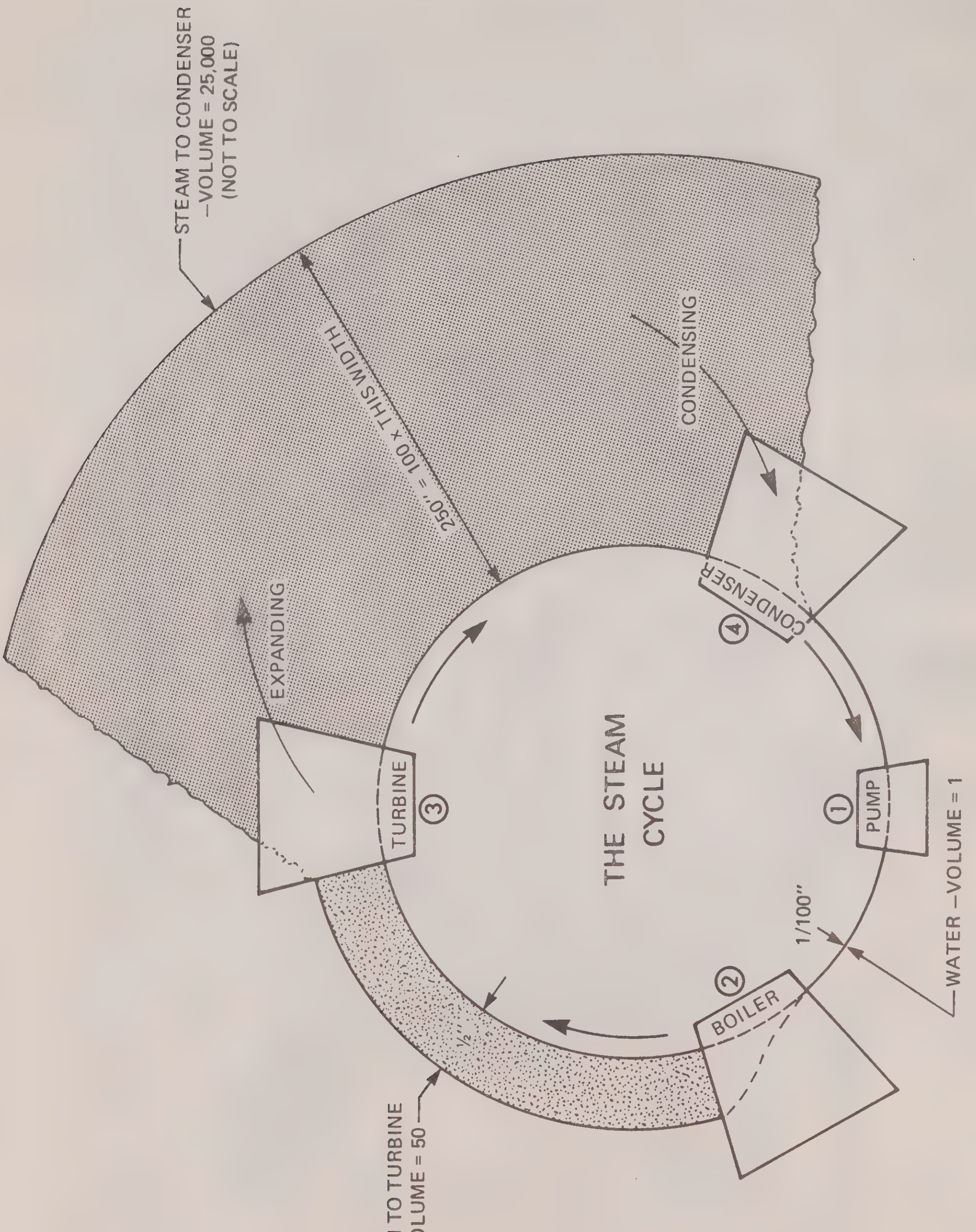


DIAGRAM OF A SIMPLIFIED NUCLEAR STEAM CYCLE SHOWING RELATIVE VOLUMES OF THE WORKING FLUID

DIAGRAM F

back into the boiler presents a formidable problem. How can a roomful of steam be put back into a pint bottle?

Basically there are two ways:

- The steam could be compressed in a compressor which would act like a turbine working in reverse. Unfortunately such a system would require almost as much power as the turbine produces.

- The latent heat could be removed from the exhaust steam, allowing it to condense to water. The water would then be pumped back into the boiler--a process that requires a relatively small amount of power.

Alternatively, the exhaust steam could be discharged directly to the atmosphere, and be replaced by fresh water pumped from the lake. In this case, the steam could only be expanded to atmospheric pressure and discharged at 212°F. The result would be the discharge of more heat than occurs in a condenser, and an accompanying loss in efficiency. There would also be environmental effects from the large volumes of discharged steam.

The second alternative is the only acceptable choice, and cooling water from the lake is used to remove the latent heat from the exhaust steam and to discard it to the lake. Removal of the latent heat causes the roomful of steam to condense into a pint of water once more. The water is drained to the pump, which in turn delivers it to the boiler to begin its journey again.

For simplicity we have discussed the progress of water through an elementary nuclear cycle which is assumed to have the same efficiency as a complex CANDU generating station, that is 30%.

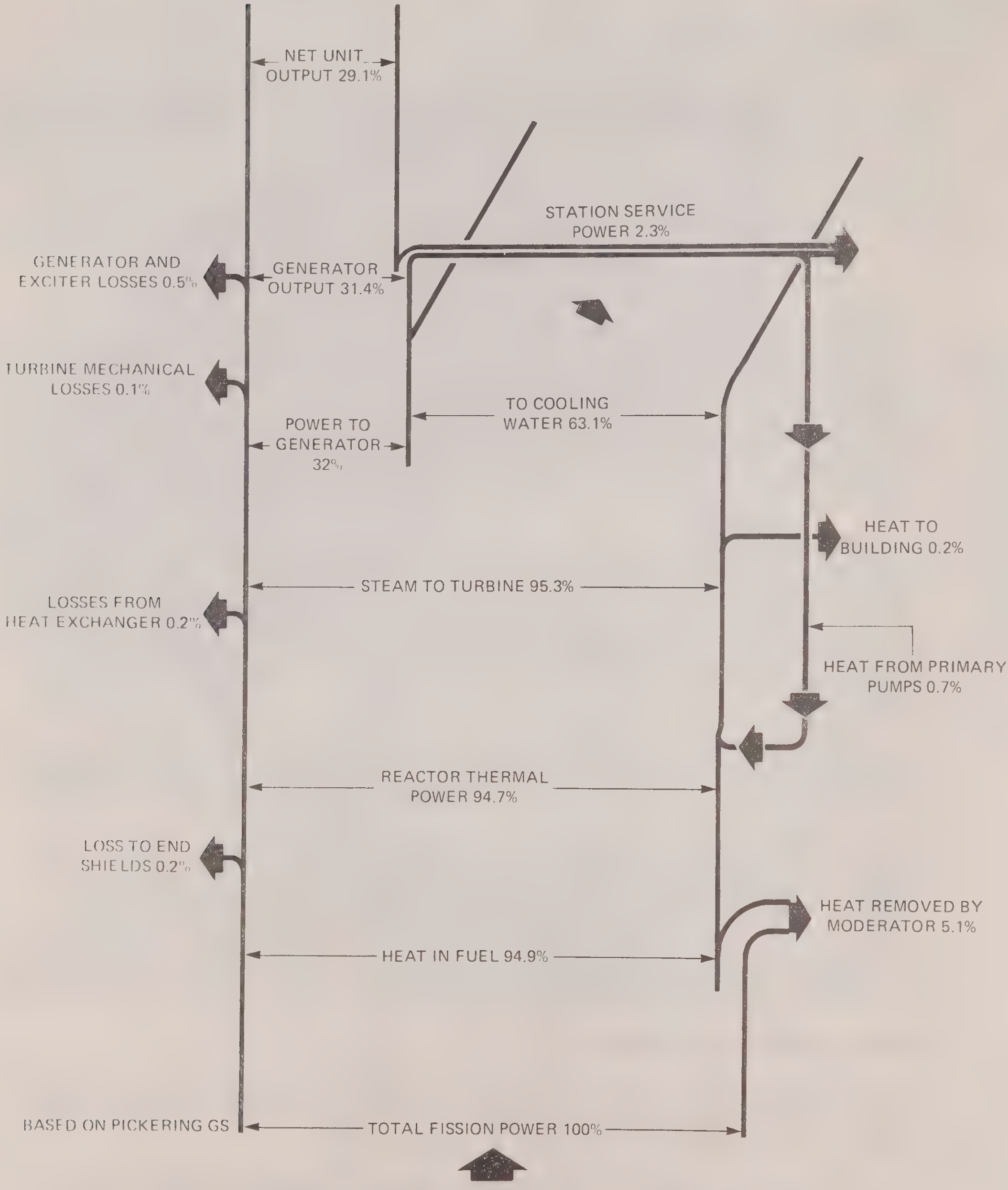
In a Candu generating station, about 70 percent of the fuel is used to supply the latent heat needed to transform water to steam, and this heat must be discarded at the end of each cycle. The remaining 30 percent of the fuel is used to add sensible heat to the working fluid, which in turn is converted to useful electrical output. Unfortunately, the latter process cannot be achieved without the former.

Distribution of Energy Flows

The preceding discussion assumed that all of the heat energy losses result from condensation of turbine steam by the cooling water. This is not strictly correct.

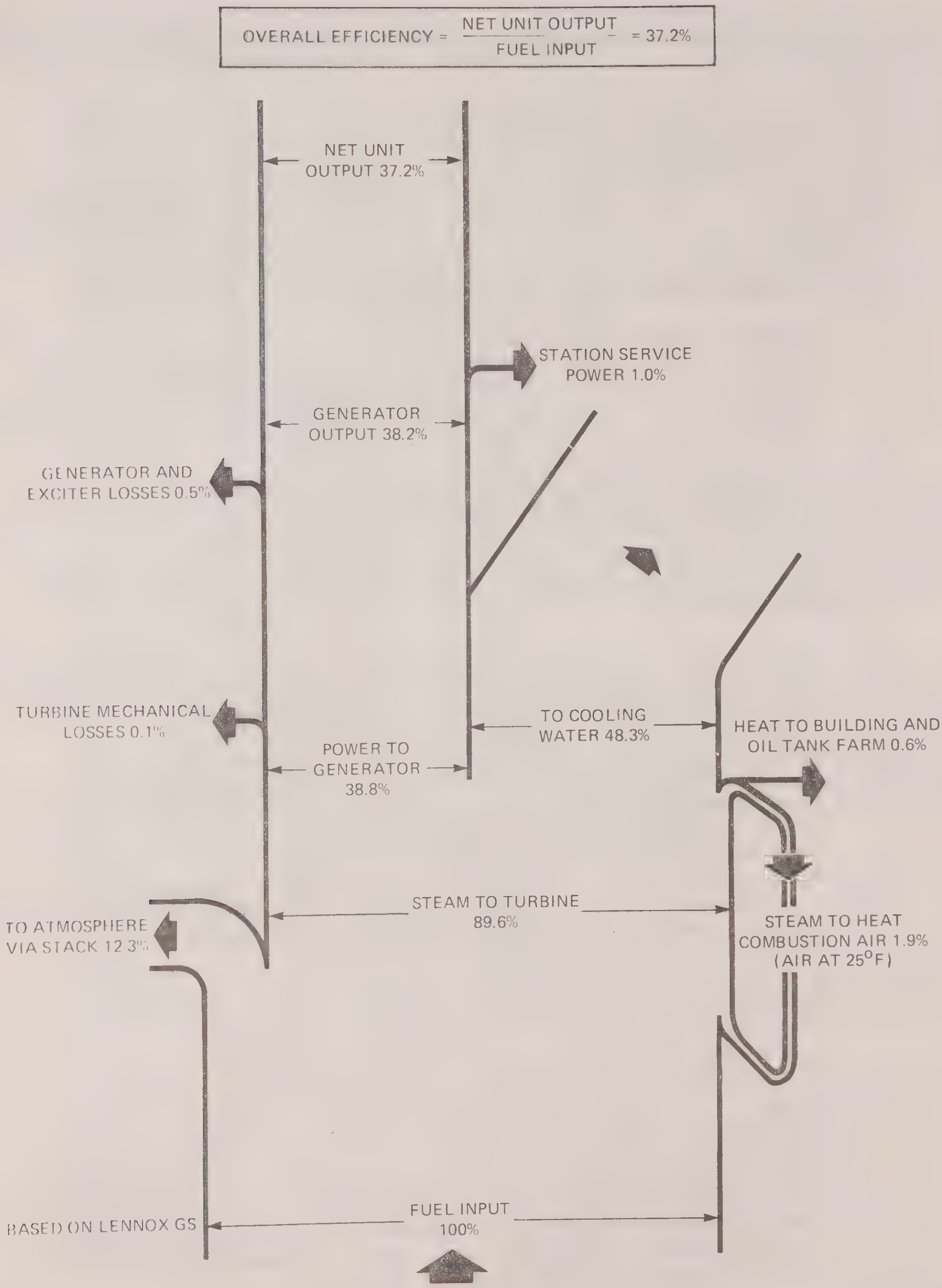
The size and distribution of the energy flows in the Pickering nuclear station are shown on Diagram G and a similar illustration for Lennox oil-fired station is given on Diagram H. Note that all of these energy streams are in the form of

$$\text{OVERALL EFFICIENCY} = \frac{\text{NET UNIT OUTPUT}}{\text{TOTAL FISSION POWER}} = 29.1\%$$



ENERGY DISTRIBUTION IN A TYPICAL NUCLEAR FUELLED GENERATING STATION

DIAGRAM G



ENERGY DISTRIBUTION IN A TYPICAL FOSSIL FUELLED GENERATING STATION

DIAGRAM H

heat except for the power to the generator (shaft power), and the generator output (electricity). The size of each stream is shown as a percent of the total heat recoverable from the fuel in the furnace or reactor.

(ii) Improvement of Efficiency

The latent heat discarded in the cooling water from thermal generating stations has long been recognized as a productive area for improving efficiency, and a number of features have been designed to reduce it. These are discussed below along with other alternatives for improving cycle efficiency.

- It has been common practice for many years to use as much of the latent heat as possible to reheat the feedwater before it enters the boiler. Through use of the latent heat in about one third of the steam that would otherwise be exhausted, the CANDU cycle efficiency is raised to 30%.

- The amount of discarded heat can be reduced by lowering the temperature at which the steam is condensed. In Ontario, the cold waters of the Great Lakes result in very low condensing temperatures and thus better overall efficiencies than for generating stations in most other locations.

- The steam cycle efficiency can be raised by increasing the temperature of the steam. In practice it is limited by the ability of the steels and other materials to retain strength at higher temperatures and pressures. For example, in spite of a great deal of metallurgical research over the years, there has been a stabilization of steam temperatures for fossil-fuelled generating units at about 1000^{o}F. Further increases are limited by evidence of longer-term problems such as boiler tube failures, which occur when units operate at too high a temperature and pressure. In a CANDU nuclear unit the limiting metal temperature is at the fuel sheath, and this controls the steam temperature to less than 490^{o}F.

- Other minor improvements to steam cycle efficiency are possible, but can only be achieved through a disproportionately high increase in capital cost or by affecting the reliability of the equipment.

- The use of working fluids other than steam may improve efficiency. The most common of these is the heated air used in a gas turbine fuelled with light oil or natural gas. However, the gas turbine has not yet surpassed the steam turbine in efficiency, nor has it yet been used to generate power from nuclear fuel. Generally it uses the most expensive of the fossil fuels.

  Many other more complex working fluids continue to be investigated, but years of development will be required to

bring a promising one to commercial reality, once it has been identified.

The utility industry is continuously studying other generating processes to improve efficiency. But it is difficult to identify a system which has sufficient probability of success in future use to commit the very large expenditures of time and resources needed for its development.

Thus, within the near future, the promise of a significant improvement in the efficiency of the thermal generation process is not as high as everyone would wish.

(iii) Utilization of Waste Heat

Opportunities and Constraints

Although power stations reject large quantities of 'waste' heat, it does not necessarily follow that useful heat is being wasted. Several factors combine to pose a formidable problem to the utilization of waste heat --the very large quantities of heat involved, the low temperatures at which it is discharged, the variability of the temperature level, and the difficulty of integrating the two highly complex systems of power generation and heat utilization.

The exhaust steam leaves the turbine at about 80° F and enters a large condenser containing thousands of tubes through which cold water from the lake is pumped. The total surface area of the tubes within a single condenser is as much as 10 acres, and the steam is condensed on the cold surfaces. The temperature of the lake water is increased by as much as 20°F in passing through the condenser tubes of a CANDU plant.

Since lake temperature varies from 34°F in winter to 70°F in summer, the maximum temperature of the heated water being discharged from the condensers, varies from a temperatue of 54°F in winter to 90°F in summer. Indeed, during the five coldest months of the year, when most heat energy is required for various space heating purposes, the temperature of the heated water stays below 55°F.

At other times, and particularly between June and October, there are wide natural variations in the lake temperature. Changing winds can cause variations in excess of 20°F in a 24-hour period. In addition, changes in unit load to meet fluctuating demands for power can alter the temperature rise across the plant by 10°F or more. Thus the temperature of discharged cooling water could vary by as much as 30°F in a single day.

Upgrading and controlling the temperature of heat discharge to the level which would make the waste heat useful for a variety of applications, has the effect of reducing the efficiency of electrical generation of the steam cycle, which, in turn,

increases the amount of heat which must be either used or discarded. It also requires the use of a specially designed turbine, known as a "back-pressure turbine", which must be operated continuously at high exhaust pressure even when there may be no use for the higher temperature heat. Back-pressure turbines are generally small and are often sized to supply a particular heat demand, and to produce electricity as a byproduct.

Another method of obtaining useful heat from a generating cycle is by extraction of some of the steam after it has provided some energy to the turbine, but while it is still at a sufficiently high temperature to provide useful heat. This system is more applicable to large generating units and the turbine is known as an 'extraction turbine'. In general, such systems must be designed into the generating unit when it is built, although with some units there may be opportunities for modification. There is also a loss in electrical output when heat is being provided from an extraction turbine. However, when there is a low heat demand or an urgent electrical demand, the steam normally extracted for heating can be redirected to electrical production. The controls for extraction systems are complex in terms of both hardware and the organization needed to establish which product (electricity or heat) has priority in times of shortage.

Although combined power and heat systems do not use 'waste heat', as the term is commonly applied to generating stations, they do have the outstanding advantage of making better use of the total heat from the fuel, providing that a predictable and reliable market exists for it.

<u>Practical Uses of Waste Heat</u>

Practical uses of low grade heat from thermal generating stations have been a subject of concern to utilities in many parts of the world for the past 50 years. This concern, coupled with more recent public interest, has resulted in considerable research and development on the subject. The areas currently being examined as having the most potential are:

- warm water swimming parks
- aquaculture
- agriculture including greenhouses

Ontario Hydro has been involved in studies on each of these items. The economic incentives for any of them seems low. It is expected that a warm water park near a generating station outfall would be the most feasible. Prototype projects may be justified, the most likely being an aquaculture demonstration using warm water from the condenser, or a greenhouse demonstration using heat from moderator cooling water. Neither

of these systems could use a significant portion of the total waste heat available, even if they proved to be feasible and were committed on a large scale. However, more practical operating information is needed, and should be obtained as resources become available to undertake the work.

(iv) Combined Heat and Power Generation

Combined heat and power generation can result in improved efficiency* of energy use compared with independent generation of heat and electricity. The overall cost of heat from such systems is dependent on many things including the fuels used at the power plant and those displaced at the point of heat use. Of particular importance is the capital cost of the heat transmission and distribution systems. This section discusses some of the considerations for industrial process heat and district heat supply in Ontario.

The Cold-Condensing Power System

In Hydro's modern and efficient steam-electric generating stations, designed and optimized solely to produce electrical energy, steam supplied from a boiler at high temperature and pressure expands through a turbine to low pressure and temperature doing work to drive the electrical generator in the process. The low pressure, low temperature exhaust steam leaving the turbine enters the condenser - a large heat exchanger cooled by lake water - where the steam gives up its latent heat of vaporization and is condensed to liquid water.

The condenser is maintained at as low a temperature as possible in order to allow the steam to expand through the turbine to as low a temperature and pressure as possible, thereby maximizing the amount of work obtained from the steam and increasing the efficiency of the generating station; in fact, the condenser actually operates at a vacuum and the temperature of the exhaust steam is as low as 80°F. The condensed water, which is of very high purity, is pumped back into the high pressure boiler to repeat the cycle. Steam turbine cycles which operate in this manner are described as "cold-condensing".

Although the quantity of latent heat rejected as the steam condenses is large, it is virtually unusable because of the low temperature at which it is available; the temperature of the cooling water leaving the station varies from 54 °F in winter to 90°F in the summer.

In Hydro's fossil-fuelled generating stations, designed to produce electrical energy only, typically 38% of the heat supplied by the fuel is made available as electrical energy from the station; about 10 to 12% of the heat cannot be recovered from the boiler flue gases, and is discharged up the stack to the atmosphere, and about 50% of the heat supplied by the fuel is discharged to the condenser cooling water. In Hydro's nuclear generating stations, about 30% of the heat

*Efficiency is defined as: $\frac{\text{Useful Energy Output}}{\text{Energy Input}} \times 100\%$

released in the reactor is made available as electrical energy from the station and about 68% of the heat is rejected in the condense cooling water.

Combined Heat and Power Systems

When heat is required for space heating or for use in an industrial process, and is generated directly and independently of electrical power generation, by burning a fuel in an efficient modern boiler, up to 80 to 90% of the heat released from the fuel will be available as useful heat, depending on the boiler efficiency. The remaining heat is lost with the boiler flue gases.

When there are coincident requirements for both heat and electrical power, and costs are favourable, combined heat and power generation can result in improved overall efficiency of energy use compared with independent generation of heat and electricity.

Back-Pressure Turbine

One approach to combined heat and power generation is the use of a "back-pressure" turbine in which the steam is exhausted from the turbine at high temperature and pressure to supply the heating load. Although the electrical output per unit of fuel input will be reduced compared with expanding the steam to lower pressure and temperature as in a "cold condensing" turbine, the overall efficiency will be substantially higher than with independent generation of heat and power and will approach the efficiency of the boiler because all of the heat in the exhaust steam is usefully applied. In the absence of a heating demand, a straight back-pressure turbine may continue to operate at high exhaust pressure if a heat sink is provided, but compared with a "cold condensing" turbine it is an inefficient method by which to generate electricity only. Back-pressure turbines are usually smaller units sized to supply a particular industrial or district heating load and generating electrical power as a by-product.

Extraction Turbine

A second approach is the "extraction" turbine in which some fraction of the steam flow is extracted from the turbine at a point part way through the turbine; the extracted steam has already done some work to generate electrical power and the heat remaining in the steam is supplied to the heating load. The steam remaining in the turbine is fully expanded to low temperature and pressure and its latent heat is rejected to the condenser cooling water at low temperature as in a conventional "cold condensing" power station. The overall efficiency of heat and power generation will be proportional to the amount of steam extracted to supply the heating load. The pressure and temperature of the extraction point (or points) are selected in terms of the temperature requirements of the heating load. The

turbine generator and condenser can be designed so that when heating is not required, the entire steam flow can be fully expanded and the electrical output increased accordingly. Although extraction systems are usually designed into a turbine before it is built, some existing units can be modified to permit extraction.

When extraction steam is taken from an existing turbine generator unit, its electrical output will be reduced as a result and one of the costs of extracting steam will be the capital cost of replacing the lost generating capacity in order to maintain the required generating capacity on the power system. If steam extraction is restricted to off-peak periods only, it may be possible to avoid this cost penalty. Extraction is generally the more suitable approach for a large utility installation where the primary function is to supply electrical power and process or district heat is a by-product.

Opportunities for Combined Heat and Power Supply

The high cost of transmitting heat is a principal factor in the economics of combined heat and power generation. The relative economy with which electrical power can be transmitted has resulted in the development of very large central generating stations, with their attendant economies of scale, to serve widespread electrical loads. Siting considerations usually require that these stations, whether fossil or nuclear-fuelled, be located outside of the urban areas. Whereas, electrical energy can be transmitted economically over large distances, transmitting heat via a steam or hot water pipeline is comparatively expensive.

By-Product Electricity

The above conditions would tend to favour a small combined heat and power plant, matched to the heating need, and located at the industrial or district heating load, for the following reasons:

- by-product electrical power could be consumed by the industry or municipality or sold to the utility.

- the interconnection between the industry and utility would be in the form of an electrical power line, which would be present in any case, rather than more expensive heat transmission pipes.

- the heat/power system could be tailored to meet the specific heating needs of an industrial process.

- the siting constraints for the industry or utility with respect to the supply of heat are minimized.

- since the industry is connected to a large power grid rather than a specific power plant, scheduling

problems with respect to initial supply of heat and electricity are minimized.

Such plants are likely to burn fossil (or refuse) fuels and use back-pressure turbines.

By-Product Heat

On the other hand, particularly in the event of future shortages of fossil fuels for industry, it may be advantageous to locate industries with large heat demands in industrial parks adjacent to existing or planned nuclear generating stations. This alternative would probably use steam directly from the reactor or from an extraction turbine. In many instances, these features would have to be designed into the generating station and this presents scheduling difficulties for the industry, since the design decision for the station may have to be made 6 to 8 years before heat could be supplied.

District Heating

The application of combined heat and power generation systems to space heating loads through district heating has been practiced in Europe where conditions such as high fuel and power costs and high housing densities have favoured its use. In European practice, typically heat is supplied from smaller fossil-fuelled heat and power units of up to approximately 200 MW capacity and located near the heating load. Combined heat and power plants may constitute up to 50 to 75 per cent of the installed heating capacity on a district heating system with less capital-intensive straight boiler plant serving as peaking and standby capacity. Because of the high capital cost of combined heat and power plants, it is most economical for growth in the heating load to be supplied first using straight boiler plant and for the combined plant to be brought into service only when a heating load has been established of sufficient size to justify the expenditure; at this point the straight boiler plant assumes a role of peaking and standby service.

In Ontario, as already mentioned, siting considerations for both fossil and nuclear-fuelled generating stations generally favour sites located some distance from urban areas. This introduces the necessity for high capital cost heat transmission pipelines if these plants are to supply heat for district heating. An alternative would be small 200 MW plants located in the urban areas, if this were acceptable to the public; this approach would suffer from a loss of economy of scale compared with larger plant. Supplying heat from large generating units, particularly through a single transmission line, would require increased standby heating capacity compared with smaller units located on the district heating system.

Distribution piping systems for district heating are also very expensive. Although work is in progress to develop new

materials, experience has shown that protection of buried pipe against corrosion often requires that for sizes greater than 2 to 3 inches, the pipe be suspended in a well drained concrete culvert. When distribution piping is back-fitted into already developed areas, the additional civil work increases costs substantially compared with new development. Because of the high cost of distribution piping networks, high load densities are required for district heating to be economic. In those areas of Europe served by district heating, the majority of the population live in apartment blocks, rather than single family homes.

The availability of capital for such systems is an important consideration and is claimed to be a major obstacle to further expansion of district heating in Europe.

The load factor of the heating load and the project life are also important economic considerations because of the capital cost-intensive nature of combined heat and power schemes. Forecasting future fuel and power costs over long periods is less than certain.

Ontario Hydro recently contributed to a study on district heating undertaken by the Ministry of Energy. This study is a conceptual one which considers the extraction of steam during the daily off-peak period from the Pickering 'B' generating station, currently under construction, to provide space heating for the proposed North Pickering community. Heat would be stored in hot water contained in large unpressurized tanks for use during the day. This scheme was considered to be the most optimistic one for worthwhile study at this time, involving heat supply from uranium.

In summary, combined heat and power generation has the potential for improved efficiency of energy use and increased energy costs will tend to favour the economics of combined heat and power generation. Consideration of opportunities for combined heat and power generation must recognize many complex and uncertain factors including planning and organization, plant siting constraints, reliability of heat supply, load growth, environmental effects, fossil/nuclear fuel availability, and ultimately, costs, including the availability of capital. Ontario Hydro plans to continue studies directed towards the most promising opportunities for combined heat and power generation.

(v) Heat and Power From Refuse

Introduction

The amount of material discarded today is a concern to most people. The value of refuse can be considered from a number of points of view. Probably the most important is the recovery of

materials and energy. The combustible materials may be recovered either for their material value or for their heat energy value. The choice of these forms will depend on many factors, including the cost of recovery and the predicted future value of each commodity.

This section is confined to the recovery of energy from refuse with particular reference to the generation of electricity.

Heat in Refuse

Ordinary household refuse contains from 3000 to 5000 BTU's of heat per pound. While this is only 1/3 of that found in U.S. coal, it is higher than the heat derived from many lignite coals used in Europe for power generation.

The table on the following page provides a perspective of the energy in refuse in Ontario. While it is small compared to total electrical use, it is an important energy resource.

An Estimate of the Energy Content of Refuse in Ontario for the Year 1975

1.	Total commercial and residential refuse	6,000,000 tons
2.	Average heat content per ton	9 Million BTU
3.	Heat in total refuse	54,000,000 Million BTU
4.	*Recoverable heat (60%)	32,000,000 Million BTU
5.	Amount of U.S. coal equivalent to the recoverable heat	1,100,000 tons
6.	Electricity that could be generated from Item 5	3,000,000 MW hrs
7.	Item 5 as a percent of Ontario Hydro's coal use	15%
8.	Item 6 as a percent of Ontario's electricity use	3-1/2%

*This estimate assumes that:

- Processing and transport of refuse fuel for heat recovery is unlikely to be an alternative for some smaller communities.
- Some of the combustible material in refuse has a material resource value that is higher than its energy value. It is assumed that it will be recovered for its material resource value, and not burned.
- In preparing refuse fuel a portion of the combustible is lost during the separation process.

Refuse as Fuel

As a fuel, refuse contains adequate heat, but it also has constituents which must be recognized in the development of any process to use this heat.

In general it contains:

- a large proportion of plastics and paper from which it derives its fuel value
- non combustibles, including glass, tin cans, and structural

components, that are difficult to process

- decomposing materials
- explosives in the form of partially filled propane bottles, etc.
- a wide array of chemicals
- moisture.

The composition is generally predictable over the period of a week or month but may vary quite widely from day to day. The long term change in its general composition is less predictable, and refuse from future new products could be difficult to handle in equipment designed for today's refuse.

Types of Refuse Fuel

The development of refuse fuel is still in its infancy and much work is in progress. Some types of fuel receiving attention are listed in the order of their general development:

- whole refuse
- shredded and classified refuse
- liquified refuse
- gasified refuse.

Regardless of the type of fuel derived, the release of heat from the refuse involves some common factors. As with any other fuel, the chemical elements in the combustible refuse are all converted to hot gases in the incinerator, furnace or boiler, and these are either scrubbed or diluted before release to the atmosphere. Refuse is more difficult to use than normal fuels because its chemistry is more diverse and less predictable, and is highly corrosive to high temperature metals.

There are other factors which are more important for some refuse heat recovery processes than for others. These include material handling and storage, particulate collection from the furnace gases, and the handling and disposal of the ash and unburned residue. Thus, the type of heat recovery process selected will have quite different effects on air and water quality.

Markets for Heat from Refuse

The markets most often considered for heat from refuse are electrical power and heat generation for space heating. Each of these has its own peculiarities with regard to the heat recovery process.

In fitting the market demand to the heat supply from refuse, it is noted that the amount of;

- heat supply from refuse is constant throughout the year
- electrical demand is slightly lower in summer than in winter
- heat demand for domestic and commercial space heating is sharply lower in summer.

Since electricity derived from refuse is small in relation to total electrical use, and since the generated power would be delivered into a large electrical network, there is no need to provide 'back-up' power generation during a breakdown of the refuse burning plant.

Supply of heat, on the other hand, requires a reliable source and most European district heating incinerators have 100% backup heat supply in the form of standby oil-fired boilers. Cooling towers are generally provided, as well, to discard excess heat during the early market building years and during summer months when there is little heat demand.

For the above reasons, electrical generation may seem to be the most economic way to use the heat at a refuse incinerator. However, the corrosion problem mentioned previously has a marked influence on this decision.

High temperature steam (800 to 1000^{o}F) is required to obtain high efficiency in a steam turbine-generator. These steam temperatures require even higher boiler tube metal temperatures. A number of refuse burning plants which have attempted to operate at these high temperatures have had unbearable high-temperature corrosion rates. New installations generally use a steam temperature of less than 600^{o}F.

This upper limit on steam temperature makes power generation at an incinerator considerably less efficient and, therefore, less economic. Some combined power and heat supply systems are being built, but in other instances they apparently cannot be justified, and the output of the incinerator boiler is limited to providing hot water for district heating.

<u>District Heating Incinerators</u>

The supply of heat to district heating networks in certain parts of Europe is augmented by heat from incinerator boilers. The public acceptance of such facilities on the edge of new residential suburbs, appears to some as a commendable assent to reality. However, such acceptance has not been the recent experience in urban Ontario.

Watts from Waste

In the above discussion the burning of undiluted refuse has been considered and the problems of its chemistry discussed.

Watts from Waste is a process for firing beneficiated refuse fuel into a large utility power boiler under controlled conditions. The normal coal fuel provides 85 to 90% of the total heat requirement and the refuse fuel supplies 10 to 15%. The refuse fuel would be prepared at a municipal processing station by shredding the whole refuse and separating the light combustible fraction from it. This fraction would consist mainly of paper and plastic products, and would account for more than 75% of the weight of the whole refuse and probably 95% of its volume.

Following separation, the refuse fuel would be transported to the generating station. The remaining heavy fraction, which contains a large proportion of non-combustibles, would be directed to land fill following the recovery of any materials that may be appropriate.

This dilution of refuse fuel with coal in the boiler is believed to have several beneficial effects:

- The hot gases from the coal and refuse mix, and the concentration of chemicals from refuse is reduced to the point where high-temperature corrosion either does not occur, or occurs at an acceptable rate.

- The diluted gases from the refuse leave the tall power station stack with the large volume of heat from the boiler gases, and are assured a plume rise that is adequate for their dispersion.

- The refuse heat is used to generate power at high efficiency.

Ontario Hydro has agreed to undertake a 2 year demonstration of this system on one unit at Lakeview. The in-service date is scheduled for early 1978. Its capacity is about 100,000 tons of refuse fuel per year which is about 8% of the fuel content in all the residential and commercial refuse from Metro for 1975.

During the demonstration, the Lakeview station staff and Hydro's Research Division will monitor and analyse the boiler metals for any indication of the onset of corrosion. Such an event could terminate the demonstration.

The ability to collect flue gas particles will also be monitored, as well as, the nature and amount of ash from the bottom of the furnace. Considerable development work is still needed, but it is expected that the trials will be successful

and will show that additional boilers can be committed to this service in future.

Summary and Conclusions

The estimated recoverable heat energy in refuse in Ontario is equivalent to about 15% of that contained in the coal used by Hydro annually. If all of this heat were used to generate electricity, it would supply 3-1/2% of the Ontario demand.

There are a number of factors which limit the use of heat from refuse, the most important being its chemistry and the high capital cost of processing equipment.

Much has yet to be learned, but at present the best opportunities for heat recovery from refuse may be in:

- Supply of heat to a district heating network using low temperature incinerator boilers fired with whole refuse and located in or near urban areas. Such installations would likely need 100% back-up from oil-fired boilers in case of breakdown. Local public acceptance of the refuse delivery system and tall stack will be needed.

- Production of electricity at coal-fired generating stations using the Watts from Waste system, providing that the currently planned Lakeview program demonstrates feasibility. The refuse fuel would be beneficiated by shredding and classifying, and its delivery to remote coal-fired stations could be by rail.

- Production of liquid fuels which could be used in individual heating boilers.

Ontario Hydro's interests under its present mandate would be directed to the Watts from Waste approach.

D. Fossil-Steam Generation

Central electricity generating stations burning fossil fuel have been in operation for many years in Europe and North America. The introduction of large fossil-steam generating units into the Ontario Hydro system did not occur until operation of the first unit at R.L. Hearn Generating Station in 1951. Until that time the development of the province's water resources and purchases of power from other provinces were sufficient to meet the load growth.

Efficiency of generation using a steam turbine is dependent chiefly on the difference between the energy in the steam admitted to the turbine and the energy remaining when it is rejected to the condenser. The energy rejected is determined by the temperature of the water available for condenser cooling; and this is a matter beyond control if natural water

bodies are used. The main effort to raise efficiency has been to raise the energy admitted to the turbine by increasing the inlet steam temperature and pressure. The development of steam generators and turbines witnessed a fairly progressive increase in steam temperatures and pressures up to the 1960's. From that time and into the present it appears that a temperature barrier of about 1000°F has been reached. Beyond this temperature present technology cannot provide materials to reliably withstand the operating stresses. Pressures have also increased, usually in steps of about 200 psig up to about 2400-2600 psig as the limit of sub-critical drum type boilers. The introduction of super-critical boilers (see paragraph 6.1 C (c)), that is boilers producing steam at conditions above the critical steam point, permitted a slight gain in efficiency over the limit reached by sub-critical boilers. Super-critical boilers were developed in both Europe and North America and several came into service in the 1960's. However, because the reliability has been somewhat less than expected and because of the inherently greater difficulty in load-following with these units, there has been a return to sub-critical boilers for most new generation in the last half dozen years. Ontario Hydro has carried out evaluations of sub-critical and super-critical cycles as applied to its system requirements and decided to stay with the sub-critical cycle.

The other major trend in generating equipment design has been a steady increase in unit rating. This also appears to have reached a temporary limit in the last few years. There appear to be only very marginal economic gains in increasing sizes beyond the present maximum. At present, single-line (tandem-compound) 3600 rpm fossil-steam turbines operating at sub-critical steam pressures, have paused at an upper limit of about 900 MW. Super-critical turbines seem to have reached a similar plateau at 1300 MW.

Increasing the turbine ratings has produced a reduction in the capital cost per kilowatt as a result of the realization of economies of scale. This now seems to be approaching a limit. Large turbines because of their proportionally greater metal masses are susceptible to greater thermal stresses induced by temperature differentials in the shells and rotors. For this reason they require a longer start-up period and are less suitable for load-following then smaller units. Ontario Hydro has not progressed beyond unit sizes of 500 MW to date, although 750 MW units may be appropriate for future stations.

Large fossil-steam generating stations were first introduced into the Ontario Hydro system in 1951 primarily for the purpose of meeting peak loads, and of providing energy under low water conditions at its hydraulic stations. The lower cost hydraulic power then available could provide most of the base load requirements. As the load has grown, more fossil-steam stations have been added and the percentage of base load carried by them has necessarily increased; but meeting peaks is still an essential role for these stations. The introduction

of nuclear generation with its lower operating costs is expected to limit development and operation of fossil-steam stations for base load supply. Therefore, existing and future fossil-steam stations are expected to operate primarily in the intermediate load and peak load range.

With the exception of Lennox GS which was designed to burn residual oil and is currently undergoing commissioning, the stations currently operating in the system were designed to burn bituminous coal from the Appalachian region of the United States. The quantity of U.S. coal burned in 1975 was about 7.5 million tons. The R.L. Hearn station originally designed for this coal has undergone a conversion in order to burn natural gas as well as coal. This was done as a means of reducing the SO_2 emissions from this Metro area station. Two units totalling 300 MW are being added to the existing one 100 MW unit at Thunder Bay in the West System. They are designed to burn Saskatchewan lignite as a primary fuel with the capability of burning sub-bituminous and bituminous coals from Western Canada if necessary.

In the period up to 1990, it is planned to meet part of the future increases in coal requirements in the East System with bituminous coal from Western Canada. Delivery of this coal is expected to start in 1978 and reach about four million tons by 1980. The western coal is quite low in sulphur and will therefore reduce SO_2 concentrations in the flue gas below those produced by medium sulphur U.S. coal. At existing coal-fuelled stations, it is planned to blend the Western Canadian coal with the U.S. coal to produce a sulphur level which will more than meet SO_2 air quality regulations. Since some sulphur is required in the boiler gas to precipitate the fly ash, there are potential problems associated with collecting fly ash from low - sulphur Western coal. The blending of U.S. and Western coal shows promise of resolving this problem. The successful development of flue gas desulphurization systems for the purpose of removing SO_2 from flue gas would permit the burning of more high-sulphur coal while still meeting the air quality regulations. The development of these systems has, however, been disappointingly slow and the cost estimates have increased at a very great rate. It appears that reliable systems will not be available earlier than the 1980's and their cost will be very high. The blending of low sulphur Western Canadian coal with medium sulphur U.S. coal therefore appears to be a very positive and reasonable approach to lowering SO_2 emissions in Ontario.

E. <u>Nuclear Power</u>

Nuclear units currently available generate electricity by using subcritical steam turbines. The steam is obtained by using heat produced as a result of nuclear fission, i.e., the splitting of heavy atoms.

For over twenty years there has been a close association between Atomic Energy of Canada Limited and Ontario Hydro directed toward development of nuclear power. There has been a general understanding that the two corporations would integrate their talents and services to provide a single non-overlapping capability from basic research to plant operation to develop the CANDU system. With the successful performance at Pickering GS, an important milestone was reached in the development of nuclear power in Canada, at a critical time of energy supply to this province. The CANDU natural uranium system provides the opportunity for Ontario to become again essentially self-sufficient in the source of energy for the generation of electricity as it once was in the days of abundant hydraulic resources. It also provides the opportunity of doing this at low cost, using the talents, experience and manufacturing capability available in Canada.

During 1972 a major review of nuclear power in Ontario was undertaken, at the request of the Government of Ontario, by Task Force Hydro. The report containing recommendations was submitted in February 1973 (Reference 6.1(6)).

Task Force Hydro agreed with the choice of CANDU reactors for nuclear power in Ontario. Of the eighteen recommendations in this report, most of which have been or are being implemented, three relate specifically to the future nuclear power program of Ontario. They are:

Task Force Hydro Recommendation 3.2

Nuclear power stations be of the CANDU-PHW (Pressurized Heavy Water) type unless future studies and assessments reveal that some alternative type will more closely meet the needs of the province of Ontario.

Task Force Hydro Recommendation 3.3

In recognition of the need to gain more operating experience and confidence with existing types of CANDU reactors and more knowledge of the economies of multiple unit manufacture, changes in design and type be resisted unless clear economic advantages can be demonstrated.

Task Force Hydro Recommendation 3.4

Ontario Hydro continue the assessment of other nuclear power reactors.

A number of events since 1972 have supported the choice of CANDU reactors as well as the choice of nuclear power over other alternatives.

At the time of the Task Force Hydro review in 1971-1973, only the first two units at Pickering had started up and were operating satisfactorily. The total station was completed

ahead of schedule and for the total cost of $375 per kilowatt installed. The 15 reactor-years of operating experience at Pickering have confirmed the high performance low-cost capability of the CANDU nuclear station. Two significant difficulties have been encountered, one related to leakage of hydrogen from the electrical generator of all the units and the other to small cracks in some of the pressure tubes of units 3 and 4 which are of a different alloy of zirconium than those on units 1 and 2. Both of these problems have required large-scale maintenance efforts by the operating staff and are being resolved. They are not considered to be generic design faults.

Since 1972, the 220 MW prototype reactor at Douglas Point has experienced a very satisfactory improvement in performance after a number of years of difficulties. It is now operating in the dual mode of supplying steam to the Bruce Heavy Water Plant A and of producing electrical energy. The average capacity factor for 1975 was in excess of 80%.

Since the start-up of Pickering GS, the CANDU reactor has gained wider acceptance outside Ontario. 600 MW CANDU nuclear units similar to Pickering are being constructed in the provinces of Quebec and New Brunswick. The federal agency, Atomic Energy of Canada, has sold CANDU plants abroad to Argentina and Korea. The United Kingdom has adopted the steam generating heavy water reactor, a variant of the heavy water reactor which uses light water for cooling; and discussions are underway for Canada to supply the necessary heavy water and some technology.

At the time of the Task Force Hydro study, the very rapid price increases in fossil fuels, which were triggered by the OPEC cartel, had not yet occurred. Since the Task Force Hydro study, the difference in cost between fossil fuels and uranium has experienced significant increases. These increases, which appear to be ongoing, reinforce the cost advantage of nuclear power.

The above events have increased Ontario Hydro's confidence in the choice of the CANDU reactor to provide for the majority of electrical growth in the period up to 1995. There are a number of additional factors. The continuing association of Ontario Hydro with the federal crown agency, Atomic Energy of Canada, in the conceptual development of CANDU continues to ensure the most effective utilization of research and engineering resources available in Ontario and Canada for the achievement of mutual objectives. The CANDU technology is wholly Canadian and yields the maximum benefit to the Canadian and Ontario economy. The manufacture and supply of materials and equipment for the CANDU reactor is almost entirely in the Canadian private sector; the nuclear industry in Canada has developed and matured to the point where it is a major and profitable factor in the Canadian manufacturing sector. The high technology associated with nuclear power creates many new

opportunities for challenging work in the Canadian employment scene.

The engineering of nuclear power stations, where capital costs are high and maintenance presents particular problems, requires a strong emphasis on quality of design to obtain high reliability and performance. To meet these demanding requirements, significant changes have been made in Ontario Hydro's organization and control of engineering effort and in the development of new skills, procedures and knowledge, based on our extensive and successful experience in the construction and operation of the Nuclear Power Demonstration (NPD), Douglas Point, and Pickering stations, and the design and construction of the Bruce nuclear generating station.

Task Force Hydro recommendations 3.3 and 3.4 were consistent with a program of studies initiated by Ontario Hydro in June 1971 involving a series of conceptual design studies to investigate the range of alternatives for nuclear plant to be constructed after Bruce A. These studies considered the engineering design, construction and financial aspects of the following: Repeat of Bruce A (4x750 MW), Improved and Uprated Bruce (4x850 MW), a 4x1250 MW CANDU-PHW station, and an assessment of Light Water Nuclear Reactors (LWRs) for Ontario Hydro. The studies showed that there were significant engineering and operating advantages in duplicating nuclear reactor units on the same site. This became the approved plan for the Pickering B and the Bruce B generating stations.

The studies also showed that the pressure tube design of the CANDU has the inherent potential for scale-up relative to other designs of reactors, and that a greater emphasis should be placed on standardizing systems and components in the nuclear reactor to simplify design and to achieve higher reliability by utilizing proven components.

Preengineering and development work is therefore now proceeding in Ontario Hydro and AECL on systems and components applicable to two standard designs of CANDU-PHW for future Ontario Hydro nuclear generating stations. These are four-unit stations using 850 MW and 1250 MW generating units. The two designs are very similar and many of the major components are identical: for example, the containment and reactor designs, fuelling machines, main heat exchangers and main pumps. The 850 MW reactor has 480 coolant channels, whereas the 1250 MW reactor has about 728 coolant channels. Both stations require the same land area.

Preliminary work is proceeding on these two unit sizes, one an improved design of the Bruce units and the other a unit 50% larger, to provide information on which to base decisions on the most economic unit size for the Hydro system and to provide alternatives for different locations in the province. In both sizes, the reactor and shield tank would be shop-fabricated and shipped via the Great Lakes. For possible power station

locations not on the shorelines of the Great Lakes system, the final assembly of the reactor-shield tank would be undertaken at the site, since the fully assembled reactor and shield tank cannot be shipped by rail or road. For some inland sites such as, for example, the upper Ottawa River, it may be feasible to ship by land a smaller size shop-fabricated reactor similar to the Pickering units.

It has always been a requirement to undertake some conceptual design studies prior to commitment of new generating plant. However, for high capital cost nuclear stations, Ontario Hydro is now involved in significant efforts of preengineering and development to more accurately predict construction schedules, capital and operating costs, plant performance and to deal effectively with difficult and time-consuming engineering and safety analysis prior to commitment for construction. This practice is based on the premise that if the preparation of major specifications and the preengineering of a nuclear plant is thoroughly undertaken prior to commitment to a fixed schedule, there is greater assurance of achieving an orderly design process with fewer changes and of meeting the performance and cost targets. A similar practice has been adopted by major utilities in the USA and UK.

A significant portion of the preengineering and development being done is independent of a designated site location. Many of the station features can be designed to be satisfactory for many geographic locations that might be available in Ontario.

Pickering performance, the engineering of the Bruce station, and the above studies have led Ontario Hydro to believe that, provided adequate capital can be made available, the CANDU is the best choice for the future energy requirements of the province. The growing experience and resources of Ontario Hydro, AECL, and the Canadian nuclear industry can best be utilized for the benefit of the economy of Ontario by the continued development of the CANDU reactor system.

Assessment of the application of the U.S.-designed light-water reactor in Ontario did not show any economic advantage and did show some technical and logistic difficulties in comparison to the CANDU for base-load energy production. Since the completion of this assessment, which used data available in 1972, several situations have developed which reinforce these conclusions.

The U.S. reactors, on an enriched once-through fuel cycle, use about twice as much mined uranium per unit of electrical production as the CANDU on a natural once-through fuel cycle, primarily because of lower neutron economy. In the past year, a significant shortage of uranium for forward delivery in the 1980's has appeared, which has sent the U.S. domestic price for uranium from about $7 per pound before the oil embargo of 1973 to over $30 per pound in 1975, and is forecast to soon reach $45 per pound. Most of the western world's enrichment is

supplied by plants of the United States Atomic Energy Commission and the demand for uranium-235 enrichment throughout the world is predicted to exceed supply in the 1980s. European and Japanese governments are anxious to become at least partially independent of this U.S. monopoly and are making very large investments to develop alternative facilities. Also, the cost of enrichment production, which is energy-intensive, has escalated substantially.

An additional consideration is the reprocessing of spent fuel. Because the LWR is an inefficient user of mined uranium, there is great pressure to develop the capability to recycle the plutonium produced during operation of the reactor and which is present in the spent fuel when it is removed and stored. The United States plutonium recycling program has run into difficulty and has not proceeded as expected. However, the apparent domestic shortage of mined uranium which would result if recycling was not introduced into the U.S. nuclear program, and the consequential economic penalties of storing and not obtaining the plutonium dollar credit in the spent fuel makes the success of this program very important to the U.S. utility industry. It should be pointed out that a plutonium-uranium fuel cycle in U.S. reactors still only brings their net fuel consumption down to the level of the present CANDU on a natural once-through fuel cycle. This is one of the factors behind the U.S. and European efforts to develop the liquid metal fast - breeder reactor with its very efficient fuel consumption.

A unique feature of the CANDU system is that it can be developed in an evolutionary way to accommodate new fuel cycles as the economic situation dictates. Conceptual studies by Atomic Energy of Canada Limited include a plutonium recycle with uranium, plutonium recycle with thorium, and a thorium self-sufficient cycle. These fuel cycles could be introduced into our present CANDU reactors without having to modify them significantly. With such recycles, improvements in efficiency of fuel consumption are a practical realization today. AECL is now planning a long-range recycle fuel development program to increase the utilization of our nuclear fuel resources in CANDU reactors. Its objective will be to develop and demonstrate a Canadian capability in the use of uranium-233. As well as developing the technological and economic base, it is important to learn all the implications of using advanced fuel cycles, such as the control of fissile material, health hazards and how to minimize them, safety of fuel plants and the reactors using the fuel.

Ontario Hydro regards this national program favourably and proposes to participate fully in its development. It seems to be the best prospect for ensuring continuation of low cost and secure energy for the people of Ontario. The current uncertainties of long term uranium supplies and future discoveries can be offset by a vigorous program of plutonium and thorium utilization backed up by world development of fast breeders and fusion to ensure that adequate energy will always

be available. Significant utilization of these advanced fuels and technologies is expected to be well beyond 1995.

F. Gas Turbines

In a gas turbine cycle, air is compressed to a high pressure, fuel is added, the mixture of air and fuel is ignited, and the resulting high temperature mixture of air and combustion products is expanded directly through the blades of a turbine, causing them to rotate and drive a generator to produce electrical power. When the gas has been expanded to atmospheric pressure, it can do no further work and the heat remaining in the gas can either be discarded to atmosphere in the high temperature stack gases, transferred to the incoming air/fuel mixture to preheat it, or transferred to a steam boiler to produce steam for a conventional steam cycle.

Because of basic process requirements, gas turbines are able to operate at higher temperatures than steam turbines and therefore have potential for higher efficiencies. A simple cycle has an efficiency of about 27%, while a heat recovery cycle has an efficiency of 33%. Combined gas turbine and steam turbine cycles (Section G) are a more recent development and their efficiencies are claimed to be higher than those of large fossil-steam generating units.

Because the moving parts of a gas turbine are exposed directly to the combustion products, a fuel with very little corrosive impurities (such as sulphur, vanadium, sodium, etc.) must be used. In practice either distillate oil or natural gas are used. Residual oil may be used if clean-up systems, currently being developed, become available. Firing of coal directly in a gas turbine is impractical because of the erosive effect of coal ash and the corrosive effect of sulphur compunds on turbine blading. The necessity of using scarce, high cost fuels is a serious drawback to gas turbines. In the longer term, the development of coal gasifiers or fluidized bed combustors may enable the use of coal-derived fuels in gas turbines thus overcoming present fuel limitations.

In addition, the lifetime and reliability of gas turbines are poorer than those of steam turbines and the maintenance costs per kilowatt are higher. However, in some utilities the low capital cost of these units may make them attractive for peak load or reserve duty where they can supply power during short periods.

The purchase of gas turbines cannot be justified for peaking duty on the Ontario Hydro system at the present time, although they are purchased for a standby power supply at fossil and nuclear generating stations. Gas turbines have also been purchased to meet the need for additional generating capacity on short notice. All of Ontario Hydro's existing units are

used for reserve and peaking duty, and all use No. 2 fuel oil which is both scarce and expensive.

G. Combined Gas/Steam Turbine Plant

Growing interest has been shown over the past few years in combined cycle (gas and steam) power stations. These stations comprise a gas turbine unit whose exhaust gases are fed into a heat recovery boiler which produces steam to drive a steam turbine. The boiler may or may not have a supplementary burner.

The use of gas turbines with heat recovery equipment which produces steam for electrical power production and/or for process work has become fairly common in the chemical industry. In many of the existing plants, the gas turbine supplies preheated combustion air to a conventional type boiler which is capable of independent operation using a forced draft fan when the gas turbine is out of service. In other applications, the gas turbine exhaust is used to heat feedwater. Here again, the steam cycle can be operated independently if the gas turbine is out of service.

Several companies have offered combined cycle plants to the power industry. The proposed plants use the package concept. They are quite different in design and proposed modes of operation from the existing combined cycle plants in North America.

From the point of view of the turbine industry, the combined cycle proposal is regarded as a logical development following from the recently greatly expanded production of gas turbines and their use for peak power generation. The manufacturing industry offers the combined cycle as having the advantages of low capital cost per kilowatt, short installation period, capability for daily starting and short duration of operation, plus an efficiency of about 40%. This makes the plant suitable for use in the so called "mid range" or intermediate mode of operation. Another advantage of a hybrid plant is its relatively low cooling water requirement. If the steam is generated by a purely waste-heat boiler without supplementary firing, the condensate in a combined process is less than half that of a normal steam cycle; accordingly the heat to be dissipated in the condenser is also reduced to less than half.

The current GE and Westinghouse versions of the combined cycle is very similar to that which Sulzer has developed and installed in Europe. These installations are the Neuchatel and Socolie plants in Switzerland and Belgium. These are about 26 MW (19 MW gas turbine, 7 MW steam turbine) and 46 MW (23 MW gas turbine, 23 MW steam turbine) respectively. They went into service in 1968 and 1969.

The Public Service Company of Oklahoma has installed a combined cycle plant near Lawton, Oklahoma. It is a Westinghouse PACE-260 (2-70 MW gas turbines, 1-120 MW steam turbine). The gas turbine started service in late 1973 and the steam turbine in 1975. The New Jersey Power and Light Company has completed the first phase of its combined cycle plant and have in operation 4 GE gas turbines (Model 7000). Boiler and steam turbines are expected to be in operation by March 1977.

The most important aspect of the new combined cycle plants is that they are designed for continuous power production, if necessary. They are not conceived as schemes to use gas turbines as adjuncts to more or less conventional plants in order to increase the capability for meeting peaks. They are capable of normal base load operation without the gas turbines. The gas turbines may be capable of operation alone or in combination with the steam turbines; but they must operate with the steam turbines if the combined plant is to provide the peak capacity and the low heat rates predicted by the designers.

The two main suppliers of combined cycle equipment in Canada and the United States, GE and Westinghouse, have not yet accumulated much operating experience on their equipment operated in a combined cycle capacity. Therefore, it would be premature to draw any definite conclusions as to the performance of this equipment at this time.

As noted in Item F, the need for scarce high quality liquid or gaseous fuels is an important factor when considering the simple cycle gas turbines used for peaking duty. It is even more important with the combined cycle which is designed to operate half the hours in a year, and will thus have a much higher annual fuel consumption.

If fuel cleaning systems currently under development can demonstrate satisfactory and economic operation using crude or residual oil, and if the reliability and maintenance costs of gas turbines can be brought to a satisfactory level, the combined cycle will become considerably more attractive for power generation.

H. Diesel Engines

Diesel engines are sparkless internal combustion engines in which the temperature change resulting from the compression of the air fuel mixture in a cyclinder is sufficient to ignite the fuel causing the gas to expand and drive a piston. The piston is coupled to a shaft which drives a generator to produce electrical power. Commercially available diesel engine generators are reported to be capable of achieving efficiencies of up to 36% with no exhaust heat recovery.

Organic bottoming cycles are being developed to utilize the waste heat in the diesel exhaust and in the diesel cooling water, to produce additional power and improve efficiency.

Among the advantages cited for diesel engines are high efficiency, short construction lead times, increased siting flexibility, lower capital cost than steam plants, and the possibility of transmission savings through dispersed generation.

However, diesel engines require expensive fuel, are not suitable to manufacture in large sizes to permit economy of scale, and have higher maintenance costs and shorter lifetime than steam turbines. These disadvantages more than offset the advantages and the use of diesel engines is restricted to power generation in remote areas, to meeting short term peaks in some systems, and to providing standby power.

Ontario Hydro uses diesel engines in remote communities which are not served from the transmission network. It also has some small units for standby duty at generating stations.

I <u>Hydroelectric Generation</u>

A hydroelectric station uses the energy that water provides when falling from one elevation to a lower elevation. The water is directed against the blades of a hydraulic turbine and rotates the turbine shaft. This in turn rotates an electric generator and produces electric energy.

The maximum amount of energy that can be generated at any potential hydroelectric site is limited by the quantity of the available water supply and the difference in elevation, called the "head", through which the water can be made to fall. These factors are determined by the natural features of the site: the pattern of rainfall and runoff, the topography, and the geology of the area.

In the process of studying the development of a new site, account is taken of such factors as the extent to which dams and other works can increase the usable head, the extend to which water can be diverted from neighbouring watersheds, the feasibility of developing water reservoirs to permit water to be used in a different (or regulated) pattern than the natural pattern of inflow, and the economic and operating advantages of alternative total amounts of installed generating capacity.

In a state of nature, the pattern of runoff tends to be highly variable from one season to another and one year to another. It may be possible to develop sufficient water reservoir capacities to regulate all the water flowing into the generating station to correspond to the required pattern of electric demand. However, such complete regulation has not been possible in Ontario.

When studying a new site, one considers the cost of successively increasing the installed generating capacity and compares it with the successive increments in peak power and energy output that could be generated. At low installed capacities, the water supply may be adequate to operate the generation continuously, i.e., at base load. Generally speaking, as the capacity is further increased, the total installation cannot operate solely in the base load mode; some must operate at intermediate load, and some at peak load. With a sufficiently large installation and development of adequate reservoir capacity, it may be appropriate to use all the water for intermediate load, or all the water for peak load.

Most of the hydroelectric generating potential in the province of Ontario has already been developed.

Figure 6.1-2 outlines estimates of the larger remaining undeveloped hydroelectric generating resources. Nearly all of the remaining resources are on the northern Ontario river systems. Since there is very little electric load close to these resources, the cost of transmission needed to incorporate their output into the Ontario Hydro bulk power transmission system is a significant factor in their cost-benefit assessment. Of the potentials listed, only the development of the Albany River sites would provide a major source of energy. Few of the other potentials can provide energy greater than 50 average MW; and most of these are expected to provide benefits greater than cost only if new electric load appears close to them, or if they are developed for the peak load mode of operation.

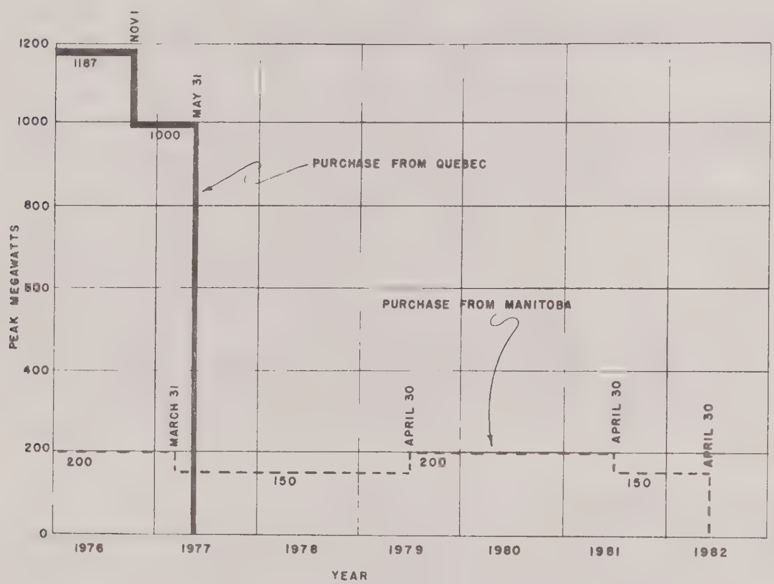
It should be noted that water from portions of the Albany River drainage basin has already been diverted for a number of years to increase the flow to generating stations on other river systems. Thus, the Ogoki diversion now directs flows from the Albany River into Lake Nipigon whence it flows into the Great Lakes and St. Lawrence River. The Lake St. Joseph diversion now directs flow from the Albany River into the English River, whence it flows into the Winnipeg River and ultimately into the Nelson River. Figure 6.1-2 is arranged to show the potentials which are unaffected by these diversions and changes to them, and the potentials which are affected.

The development of the Albany River to its estimated installed generating capacity of about 3200 MW requires the construction of about 15 power dams and a significant number of additional control structures to divert water into the Albany River from the Whiteclay, Winisk, and Attawapiskat Rivers. It also requires discontinuing or drastically reducing the present diversion of the Ogoki and the Lake St. Joseph out of the Albany watershed. If it is undertaken, it would adversely affect the existing and possible future developments on the English, Little Jackfish, Nipigon, Niagara, and St. Lawrence Rivers; and the Winnipeg and Nelson Rivers in Manitoba.

J. Firm Purchases from Other Provinces

Ontario Hydro has had a long history of firm power purchases. It has purchased firm power from Quebec since the 1920s, and from Manitoba since 1972. These purchases were made when Ontario Hydro required power and when it was available at advantageous prices.

The firm purchases currently covered by contracts or letter of intent are:



The contracts and agreements for the above firm purchases reflect the recent fundamental changes that have taken place in the nature of firm purchases.

187 MW of the purchase from Quebec terminates on November 1, 1976. This contract was originally executed in 1929, and was amended a few years later. The amended agreement provided fixed amounts of power and energy which ratchetted up in the initial years. The final amount of 187 MW has been supplied for almost 40 years, at a fixed price. It has been associated with a specific generating station, at Beauharnois. Several similar long term purchases were made from other Quebec sources but these have already expired.

The remaining 1000 MW purchase from Hydro-Quebec will terminate on May 31, 1977. This is purchased under two agreements of much shorter duration than for the above 187 MW. The first agreement was executed on October 2, 1970, and stipulated the delivery of certain amounts of interruptible energy starting June 1, 1971, and of firm power and energy starting June 1, 1975, all purchased at fixed prices. The second agreement was executed on November 24, 1971, and provided additional energy and firm power at higher prices, which included the concept of a varying price for the additional energy that escalates by stated amounts, year by year. This power and energy was not related to a specific generating station; but in principle it became available as a result of a temporary surplus in Quebec associated with the Churchill Falls hydroelectric development.

A similar situation applies to the purchase from Manitoba Hydro. This represents three agreements each of short duration. The first was executed on November 16, 1971, and provided certain amounts of firm power and energy for delivery up to March 31, 1978. These are purchased at a fixed price. The second was executed on January 30, 1974 and May 21, 1974, and the third on May 28, 1975. They provide power and energy in the period April 1, 1977 to April 30, 1982. The second and third agreements have common terms and price. This price is to be related to specific actual escalation factors and actual interest rates that occur up to 1980. In essence these agreements were made possible by a temporary surplus in Manitoba associated with Kettle Rapids for the first agreement and Long Spruce for the last two agreements. These are both hydroelectric developments.

Thus, the nature of recent firm purchases has changed from the earlier concept of fixed amounts of power and energy supplied for long periods of time at fixed prices, to the concept of supply for:

(a) Relatively short periods of time. These times are associated with temporary surplus capacity on the seller's system.

(b) At variable prices, related to estimated or actual future escalation rates.

These temporary surpluses on the seller's system have resulted from the power and energy from large-scale hydroelectric developments overrunning the seller's own requirements, or the deliberate advancement of some stages in these developments in order to achieve surplus for use in firm sales to markets outside the seller's system.

Prices now quoted by sellers tend to be at least the larger of either the average cost of his new developments or the average price to his own firm customers. Higher prices than these are quoted if the seller believes the market will bear them.

Up to the present, sellers have not required Ontario Hydro to provide capital contributions toward development of generating stations. Current indications are that sellers may require such contributions for future large scale firm sales.

These changes in conditions of sale tend to render purchases less attractive, by reducing the advantages formerly available to the purchaser, namely:

(a) A reduction in the amount of capital the purchaser must raise. (If, in future purchases, the seller requires the purchaser to make a capital contribution).

(b) Low prices associated with the incremental cost of advancing new projects or with surplus sales. (If prices are based on the seller's average project costs or on rates charged to the seller's own customers, and these are greater than incremental cost of the projects. From the seller's viewpoint, such prices may be necessary from the provincial political viewpoint.)

This is of particular concern where the seller is developing hydroelectric capacity, on the assumption that the energy production costs from alternative thermal plants that he could develop will continue to escalate in the future. In such cases, the average cost of the hydroelectric development, although lower than thermal plant costs in the long run, may be higher in the early years when the seller has excess power and energy to sell to Ontario Hydro. In this case, the selling price to Ontario Hydro would be higher than Ontario Hydro's costs from alternative thermal plants.

Two major factors affecting the benefits of firm purchases are their nature (whether they are derived from thermal or hydroelectric generation) and the extent to which idle electric transmission and fossil fuel transportation facilities exist in the areas involved.

The cost of transmitting electrical energy long distances tends to be higher than the cost of transmitting equivalent fossil fuels by rail, ship, or pipeline. This is particularly the case where usable rail facilities are already available. It may not be the case where little, if any, new electric transmission must be constructed and where rail rates are rigidly structured to reflect average historical costs rather than the incremental costs of rail delivery. Thus, when the present 200 MW purchase from Manitoba Hydro expires, it may prove economic for Ontario Hydro to import electric power instead of additional coal from Saskatchewan. This possibility is being investigated. It hinges upon the reliability of the Manitoba Hydro system and their willingness to transmit power from Saskatchewan to Ontario.

Hydroelectric energy must be transmitted electrically. If this requires new transmission, a large cost penalty may be

involved. However, under Ontario Hydro's proposed transmission systems, by the end of the 1970s it could import 1000 MW to 1200 MW from Hydro-Quebec and 200 MW to 300 MW from Manitoba.

Ontario Hydro is continuing its past practice of pursuing the possibilities of making firm purchases from other provinces and making such purchases when they are advantageous. This is done by periodically reviewing the possibility of purchases from Hydro-Quebec, Manitoba Hydro, and Saskatchewan Power Corporation.

At present, preliminary proposals for sales of firm power to Ontario from April 1977 to March 1979, and from April 30, 1981 onward have been received from Manitoba Hydro and Saskatchewan Power Corporation. A preliminary proposal for sale of energy from May 31, 1977 onward has been received from Hydro-Quebec; but at the present time Hydro-Quebec has indicated that it is unlikely to have firm power available for sale in this period.

Section 9.0 discusses the value of interconnections with these utilities for purposes other than the purchase of firm power.

K. Energy Storage

Energy is stored in such primary forms as fuel in coal piles or in oil storage tanks, and as potential energy stored in water collected behind a dam. Storage of converted energy such as heat or electricity is an attractive alternative only when the demand for energy varies periodically with time and it is more costly to match this demand directly with primary energy conversion facilities than to match part of the variable demand with an energy storage system. Such a situation appears likely to emerge with developing nuclear generation programs. As increasing nuclear capacity is added to the generation system, this base load source of energy may eventually be in excess of system energy demand for some parts of the day during some parts of the year. This will necessitate either load cycling the nuclear units or the utilization of suitable storage facilities to receive nuclear energy during off-peak periods and return it to the system during peak periods. This will allow the units to continue to operate on non-cycling base load.

When comparing various energy storage facilities, the factors which are important are capital costs in $/kW, reliability or dependability, input-output efficiency, storage density and practical storage duration. Some types of storage that have been proposed as possible candidates for use with nuclear generation are described below. For further information, see Reference 6.1(5).

a) Aboveground Hydraulic Pumped Storage

This is the only developed large scale energy storage concept. It utilizes the ability of an elevated mass of water to produce energy as it flows to a lower elevation. Excess electric energy is used to drive the motors of large pumps which lift the water to the higher elevation storage reservoir. When there is a demand for energy, the water is released to a lower reservoir and generates electricity by the conventional means of a hydraulic turbine-generator.

The stored energy can be held for long periods of time since losses from the upper reservoir are mainly the result of the slow processes of evaporation. Storage densities are dependent on the elevation difference between the upper and lower reservoirs and are comparatively low. Storage of significant amounts of energy therefore requires large volumes of stored water.

Generally, the pump and turbine is a single impeller which is connected to a reversible motor-generator. The input-output efficiency is normally between 65 and 70 percent. Operating compatability of such facilities with electric power systems has been demonstrated to be reasonably good. They have the ability to act as spinning reserve and a response time for changing over from pumping mode to generating mode measured in minutes.

The major limitation of aboveground pumped storage is the limited number of suitable sites having the required topography and land area. Many such systems are in operation around the world including Ontario Hydro's Sir Adam Beck Pumping/Generating Station on the Niagara River. Aboveground hydraulic pumped storage sites available for development in Ontario are few in number. Some of the sites studied by Ontario Hydro in the last 10 years are shown in Figure 6.1-3.

b) Underground Hydraulic Pumped Storage

Underground hydraulic pumped storage uses the same working principal as aboveground hydraulic pumped storage. The distinction is in the position of the respective reservoirs. The underground concept essentially exchanges the topographical constraint for a geological constraint, which, in southern Ontario, may facilitate siting. Only one reservoir is required at the surface. The lower reservoir is excavated below ground. When located near an existing large water body, such as Lake Ontario, only the headworks, control room, transformers, switchyard and vent shaft muffler are located at the surface. Storage capacity is determined by the excavated volume of the lower reservoir rather than the capacity of the upper reservoir.

The lower reservoir can be located at a depth limited only by available pumps and turbines. This results in increased storage density as well as improved turbine efficiency. Capital costs are predominately excavation costs for the underground works including the lower reservoir, powerhouse, transformer gallery, access and vent shafts. The freedom to select sites closer to major load centres would result in savings for transmission facilities in comparison with other storage systems. General Public Utilities (New Jersey) is conducting a detailed investigation of a 1000 MW installation at Mount Hope, and a European utility is studying the possibility of using a limestone mine for the installation of a storage system. Ontario Hydro has received a consultant's report on feasibility and cost of installing such a system in southern Ontario (see Reference 6.1(8)).

c) Compressed Air Storage

With conventional combustion turbine-generator sets only about one third of the turbine output power is used to generate electricity as approximately two thirds is consumed in driving the air compressor that feeds the turbine combustion chambers. Most proposed air storage schemes, including the only installation committed for construction to date, use excess off-peak electricity to compress air which is subsequently cooled and stored in an excavated underground reservoir. Later, this high pressure air is released to the combustion turbine to burn high grade fossil fuel and generate electricity giving approximately three times the output of the conventional arrangement. Although capital costs for such schemes are comparatively small, this is offset by high operating and fuelling costs.

An alternative scheme using compressed air has been proposed which interposes a regenerative heat storage reservoir between the compressor and the air storage cavern. This would allow the heat of compression to be conserved during the charging period and added back to the air for the generation period. With the hot air supply, the turbine would need little or no fuel and although capital costs are increased by inclusion of a heat storage reservoir, operating costs are greatly reduced.

There is at present no air storage scheme in operation. The world's first installation, scheduled for in-service in 1977, is under construction at Bremen in Germany (see reference 6.1(9)). This installation has the advantage that the caverns are constructed in a salt dome which provides an airtight geological structure, which is an important and necessary feature of such installations.

d) Battery Storage

Batteries may offer advantages over other competing forms of energy storage since they can be dispersed throughout a network and would enable transmission line cost savings to be realized; there are possible system control advantages associated with batteries; and they have a rapid start-up and turnaround time.

However, present day batteries, such as the lead acid battery, have relatively short lifetimes and are too costly for large scale installation in a power system. Several battery systems are being researched which may produce more suitable designs by the late 1980's. Ontario Hydro is currently conducting a state-of-the-art study of these systems to determine the prospects for their future application in the Ontario Hydro System.

e) Feedwater Storage of Heat

As explained in Section 6.1 C(c), in conventional steam stations steam is extracted from various turbine stages to preheat the feedwater entering the boiler. Feedwater storage involves the extraction of more steam during off-peak periods to heat additional feedwater which could be stored and used during periods of peak demand, thus eliminating the need to extract steam during these peak demand periods and increasing the power output. This scheme was first proposed in Reference 6.1(10).

Because of the high pressure, storage of the large amounts of feedwater required for, say 8 hours of energy production, in conventional steel pressure vessels, would be very expensive. The concept under investigation by Ontario Hydro involves the storage of feedwater in tanks located in large underground caverns which would be pressurized with air to balance the water pressure in the tanks. The tanks would thus be designed to retain only the load of water in them.

Conceptual studies, so far, have indicated that this system is technically feasible and shows promise of providing cost advantages. Considerable detailed design and development work may, however, be required before such an installation could be committed.

f) High Temperature Heat Storage

This concept involves the storage of water at higher pressures and temperatures than the feedwater storage mentioned above. By bleeding steam from the nuclear boiler to an accumulator, the steam flow would decrease to the turbines during off-peak periods. This steam would be condensed and stored in a similar manner to feedwater, as discussed in subsection (e) above. During peak periods this water would be flashed to steam and delivered to an auxiliary turbine to generate peak power.

The system requires the development of the feedwater storage scheme, high pressure ancilliary equipment and a special purpose steam turbine and is, therefore, somewhat more futuristic. Although an aboveground high temperature heat storage system has been proposed in Reference 6.1(11) and underground steam storage was proposed in reference 6.1(12), the system being studied by Ontario Hydro is a unique system which is not to our knowledge being investigated by any other utility.

g) Low Temperature Heat Storage

Storage of heat by the customer has been mentioned as a possible means of load levelling by enabling the use of off-peak electricity to heat homes and buildings. Heat would be stored overnight in hot water tanks, rock filled bins, or as latent heat in hydrated salts, for use in heating during the day. Ontario Hydro's Research Division has initiated a major program to develop a heat pump suitable for operation in Ontario (see Reference 6.1(15)). The heat pump would extract heat from solar heat in the atmosphere and could be used in conjunction with heat storage to reduce electricity requirements.

h) Mechanical Energy Storage

Energy can be stored in the form of high speed rotation of a flywheel. Off-peak electrical power would be used to increase the speed of rotation of a heavy disk to high speed (8,700 rpm). When power was required to meet system peaks the disk would be coupled to a generator to deliver the energy stored in its rotation. Flywheels are suitable only for short duration output application.

Friction losses introduced in bearings and windage losses caused by imperfect seals must be minimized. In large flywheels imperfections in materials will be magnified due to cycling stresses resulting from repeated charging and discharging. This reduces design materials strengths, and the amount of energy that could be stored per pound of material, to values well below those theoretically attainable in a laboratory. A flywheel failure would produce explosive energy which would require containment, possibly in an underground chamber, for safety reasons. Other problems relate to cost and the development of large variable speed motor/generators and the associated control equipment.

L. Magnetohydrodynamics (MHD)

When a gas is raised to a very high temperature (greater than 4500°F) and an alkali metal "seed" is added to it, the resulting mixture is capable of conducting electricity. In a conventional generator, a copper conductor is passed through a

high magnetic field and an electrical current is produced. In magnetohydrodynamics a conducting mixture takes the place of the copper conductor. When this mixture is expanded at high velocity through an intense magnetic field, an electrical current is produced which can be removed by electrodes placed on the generator walls. After expansion in an MHD generator, the heat remaining in the exhaust gases (which are still at 3600^{O}F) is available to preheat air and fuel entering the MHD combustor and to raise steam in a conventional steam cycle.

MHD is claimed to lessen the problems of high temperature materials because it employs no rotating parts. However, very high temperatures are necessary to obtain sufficient electrical conductivity in the gas to achieve high efficiency. These temperatures, coupled with the corrosive effects of the alkali "seed" and the combustion products, and the need to extract electrical energy at low voltage and high current in this atmosphere, make the problem of finding adequate materials much more severe than in generating methods employed to date.

The major problems facing MHD are:

- It has not yet been demonstrated that the MHD generator performance necessary to give commercially viable efficiencies (in the neighbourhood of 50%) are obtainable in practice.

- The material problems encountered in withstanding the corrosive high temperature gases and large currents must be overcome to provide acceptable performance, lifetime and reliability.

These problems are strongly linked since the efficiency obtainable with MHD increases rapidly with increasing temperature but the material problems encountered are much more severe at higher temperatures. For this reason, the feasibility of MHD hinges more on the solution of the material problems under conditions capable of producing high efficiency than on any other single factor.

The competitive position of MHD with respect to other high efficiency methods of generating electrical power (i.e. advanced gas turbines or potassium turbines) would be enhanced if it could burn coal directly. Once again, however, this may not be possible because of the severe material problems resulting from the corrosive and erosive effect of sulphur, seed, slag and ash in the duct, preheaters, and steam bottoming plant. In view of the competition from advanced gas turbines, it is probable that MHD would have to combine direct coal firing with high efficiency in order to be successful. MHD technology is at an early stage of development and is unlikely to be commercially available before 1995.

In Ontario Hydro's view, predictions of future practicality cannot be made with any degree of certainty at this time in

view of the formidable material problems. For further information see Reference 6.1(1).

M. Solar Electric Generation

Generation of electricity from dispersed low intensity solar radiation has been proposed by two distinct approaches; generation of bulk electrical energy at central generating facilities and dispersed local generation. The first approach generally prescribes the use of solar-thermal conversion by means of large arrays of independently steerable mirrors reflecting the direct component of solar radiation to an elevated boiler. Steam raised in the boiler is then piped to a conventional steam turbine-generator. Such systems appear most practical for development in areas of high annual direct solar radiation such as the southwestern United States where land areas of one square mile appear sufficient to generate 100 MW of electrical output.

Bulk power generation from central facilities using photovoltaic cells has also been suggested, but dispersed application at the load centre is generally considered more practical and compatible with the nature of solar radiation. Both methods are too costly by todays standards. For application in Ontario, photovoltaic cells have the advantages of using both the direct and diffuse or scattered radiation and, if capital costs can be reduced from present values of about $20,000/kW by a factor of 10 or more, some portion of domestic electric supply may be generated by this clean, quiet energy conversion device.

Solar energy in Ontario for application to electric generation is reviewed in Reference 6.1(4).

N. The Hydrogen Economy

Numerous proposals and studies exist for an energy economy based on hydrogen. This light, clean burning synthetic fuel is receiving attention as a possible future replacement in many applications for diminishing fossil fuel supplies. Industrial, residential and transportation uses, including automobile and aircraft fuels, have been studied. To the extent that the problems are known and understood, there is cause for optimism. The present North American practice of producing hydrogen from natural gas is obviously not viable for future large scale production. But hydrogen from coal or electrolysis is possible and other more futuristic production methods are being studied. Hydrogen pipelines although more costly due to material requirements and higher compression costs than natural gas pipelines may be environmentally more acceptable and less costly than electric transmission facilities for long distance energy transmission. The safety precautions required for gas transmission would be required for hydrogen pipelines. Most

operations involved in production, transportation and transfer of hydrogen would have to be automated to reduce the possibility of human error.

Electricity could be generated from hydrogen at, or close to, load centres after gaining the transmission advantages of hydrogen pipelines. For conversion to electricity, continued development of fuel cells and combustion turbine-generators is required. Hydrogen-produced electricity generally appears more costly than conventional electric generation methods because of the high cost of producing the hydrogen. The technology requirements for the development of hydrogen energy systems are extensively reviewed in Reference 6.1(3).

O. Geothermal Power

The interior of the earth is extremely hot, but the heat is generally too deep to be economically recoverable. In some areas of the world however, recent volcanism or shifting in the earth's crust has resulted in zones of above normal temperature and heat flow that lie close to the surface.

The major types of potentially exploitable geothermal resources are: hydrothermal, where water or steam convection currents transport heat from a deep source to drill hole depth; geopressure, where hot water is trapped under a sedimentary basin of undercompacted sand or clay and carries a large portion of the overburden weight; hot dry rock; and molten magma.

So far, only high quality hydrothermal resources have been tapped. Large scale exploitation of alternative geothermal resource is not envisioned before the year 2000.

Known hydrothermal sources are located in California (Geysers), Wyoming (Yellowstone), Italy, Japan, Iceland, Mexico and New Zealand. Hot dry rock is known to exist along most of the Pacific west coast of North America. Geopressure sources are known to exist in the U.S. along the northern Gulf of Mexico, the Gulf coast and in Wyoming (see Reference 6.1(13). Exploitation of the very deep geothermal resources in other less favoured locations, such as Ontario, may never be viable and will be dependent upon results of experience elsewhere.

P. Wind Power

Wind Power has been used in the past to pump water, grind grain and supply electrical power to agricultural communities and isolated farms. In the U.S. prior to 1950, it has been estimated that there were as many as 50,000 windmills generating electrical power at remote farms in the mid-west. The energy crisis has resulted in a revival of interest in windmills. The major obstacles to the application of wind

power on a large scale are high capital costs and high maintenance and equipment replacement costs; the variability in the wind, requiring either a back-up, or a storage system; and the dispersed nature of the wind. Most experts agree that wind power applications will be limited to areas with exceptionally strong winds or to remote communities dependent upon high cost fuels.

To avoid interference of wind current between windmills, it has been claimed that the windmills must be spaced approximately 30 diameters apart (see Reference 6.1(14)) and this limits the amount of power which could be extracted from a given land area. For example, with wind speeds typical of southern Ontario, an array of windmills spread over the entire southern Ontario land mass west of a line between Toronto and Midland, would generate only as much energy as the four units at the Pickering Generating Station. A back-up generating station or a very large energy storage system would be required to provide power on demand.

Although currently commercially available wind generators cannot produce power at prices comparable to Hydro's retail costs some individuals may choose to install windmills to supply a portion of their own load either for reasons other than costs or by constructing a unit at low material cost as a hobby.

The use and future potential of windpower is reviewed in Reference 6.1(2).

Q. Biomass

Living plants contain hydrocarbons which can be used as fuel, and man has relied on the fuel value of trees since the dawn of time.

Because trees store solar energy and are a renewable resource, the dedication of a portion of forests to supply fuel to a fossil-steam plant for electric power generation has been proposed. While such a system may be technically feasible, both its cost and its effects on the environment and on the alternative uses of wood fibres must be considered.

Forestry based industries such as the timber and pulp and paper industries have already predicted wood shortages by the year 2000 and there is an implication that not only are suitable tracts of land not available for plantation but that there are potentially more valuable uses for wood in the economy than burning it to produce electricity.

Existing hardwood forests are relatively slow growing. However, because of their comparatively high heating value, the hardwoods have been the traditional wood fuel. It has been estimated that as much as 16,000 square miles of such forests

would be required to produce the same amount of electrical energy as that from a 1000 MW nuclear plant. This is equivalent to the total land area of Southern Ontario west of a line between Toronto and Midland.

Consideration has also been given to faster growing species such as aspen poplar which are being developed for high quantity cellulose production. When developed, such species may allow a crop of trees to be harvested every ten years from suitably cultivated and fertilized agricultural type land. Although the bulk heating value of poplar is much lower than that of hardwood, it has been estimated that such a system could reduce the land area needed to support a 1000 MW generating station to one-tenth of that noted above.

The real estate value of land and its value for other uses would be critical factors in considering dedicated plantation on a significant scale. In addition, it is estimated that the cutting and delivery of wood to generating stations and its preparation for combustion in special boilers would result in costs that are at least as high as those for coal, and that the capital and operating costs of the plant would be considerably higher.

R. Comparison of Commercially Available Thermal Generation Equipment

Figure 6.1-4 shows comparative characteristics of commercially available equipment for large-scale generation of electric power in Ontario. It should be noted that, whereas liquid and gaseous fossil fuels are relatively interchangeable, units burning these fuels cannot readily be converted to coal firing, unless prior provision has been made for installation of coal bunkers and additional boiler heat-exchange surface.

Gas turbines require a refined or clean fuel such as No. 2 fuel oil or natural gas. Such units could use coal, with the addition of coal gasification facilities when such equipment is developed. This would result in a decrease in efficiency and an increase in capital cost.

The electricity production efficiency at full load does not increase with the size of unit above that already being installed in Ontario.

In the case of the gas turbine, all the rejected energy is released directly to the atmosphere. The alternatives employing the steam cycle release a portion of the rejected heat energy to cooling water. The use of cooling water from cold lakes is necessary to achieve the efficiency levels indicated. Heat release from the generating site direct to the atmosphere is possible using cooling towers, but this reduces efficiency and increases capital cost.

Figure 6.1-5 shows Ontario Hydro's current forecast of New Generating Unit Outage Indices for use in Studies of Future System Development. For nuclear and fossil-steam the Adjusted Forced Outage Rates, Maintenance Outage Factors, and Planned Outage Factors are forecast to be high in the initial year of operation, and later decrease to lower terminal values. Accordingly, the Capability Factors are initially low, and later increase to higher values. The outage indices for nuclear and fossil-steam units are about the same for units of the same size; and their reliability and capability decreases as the unit size increases.

S. Costs

This section outlines estimated capital, operation, maintenance, and fuel costs of the types of thermal generation which are considered as feasible new sources for Ontario up to 1995. These are:

- CANDU nuclear
- Fossil-Steam, coal-fuelled
- Gas Turbines, also known as Combustion Turbines

No data are included for combined cycle units, because no up-to-date estimates are available. Also, it is doubtful that adequate supplies of low-cost fuel will be available for them.

No data are included for conventional hydroelectric sources or energy storage schemes. This is in part because of the lack of up-to-date estimates, and in part because hydroelectric peaking resources and energy storage schemes are unlikely to be needed in large amounts by Ontario Hydro until after 1990.

All the cost data given in this section relate to generating stations comprising four units of identical size. For such stations, the costs per kW and costs per kWh are lower than for stations comprising one or two units.

Also, all the costs for the fossil-steam units are based on using United States coal. However, the costs shown are known to be too low because they do not include:

- the capital cost of facilities for cleaning stack gases or the cost of facilities for treatment of the delivered coal, that will be needed if the stations are to meet future air quality regulations.

- the additional cost of operating, maintenance and materials needed, and the additional power and energy consumed due to this stack-gas cleaning and/or coal treatment.

As a result, all the comparative data developed in this section show the costs of the fossil-steam plants to be lower than they would be in practice.

Capital Costs

Capital cost is defined as all the costs for material, equipment and labour needed to design, construct and commission a project including overheads and interest on funds spent on this work up to the actual in-service date.

Figure 6.1-6 shows the estimated capital costs on three bases:

- No escalation, all costs of material, equipment and labour in terms of 1976 prices.
- Escalation included, for stations with their first units coming into service in 1985.
- Escalation included, for stations with their first units coming into service in 1995.

In the latter two alternatives, escalation rates are those forecast by Ontario Hydro in 1975.

The figure shows that the capital cost per kilowatt of nuclear units is substantially greater than that of fossil-steam units of the same size; and the capital cost per kilowatt of the latter is substantially greater than that of gas turbines.

The percentage relativity of the total estimated capital costs per kilowatt is almost unchanged by escalation; but the dollar differences between alternatives increase as a result of escalation.

The figure also indicates the economy of scale, i.e., the manner in which costs per kilowatt decrease as the size of units is increased. The advantages of economy of scale progressively diminish as unit sizes are increased. Extrapolation of the figures indicates that the economy of scale will eventually disappear for nuclear units at some size greater than 2000 MW, and for fossil units greater than 750 MW.

Operating and Maintenance Expenses

Figure 6.1-7 shows the estimated normal annual operating and maintenance expenses per kilowatt, excluding fuel, for 1976. It also indicates the economy of scale: larger units have lower costs per kilowatt. Costs for nuclear units are higher than those of fossil-steam units of similar size (this is in part due to the cost of heavy water make-up and upgrading for the nuclear units).

Energy Production Expenses

These are the costs of the primary fuel consumed per kilowatthour of electricity generated. For 1975 conditions, they are estimated at:

1.27 mills per kWh, for CANDU nuclear units, 500 MW and larger

10.26 mills per kWh, for fossil-steam units using US coal, 500 MW and larger

25.20 mills per kWh, for gas turbine units

It is estimated that these costs will continue to escalate in the future, and account of this is taken in the remainder of this section.

Total Cost Comparisons

The total cost comparisons discussed in the remainder of this section encompass all the above costs, plus for the nuclear units the cost of initial heavy water requirements. Thus, the total annual costs comprise charges on capital, operation, maintenance, and fuel.

For the nuclear units, the cost of the fuel is approximated by two components: half the initial charge of the reactor which is included in the capital cost, plus the estimated equilibrium annual burnup of fuel.

The total cost comparisons for thermal generating units are given in the following figures:

Figures 6.1-8 and 6.1-9

These show the estimated total annual costs per kilowatt sent out from the generating station during its first year of operation. To simplify the figure, costs are shown for only a few unit sizes.

In Figure 6.1-8, the annual charges on capital correspond to the long-run costs. i.e., they comprise interest and sinking fund amortization to recover the initial capital cost in the assumed 30-year useful life of the facilities.

In Figure 6.1-9, the annual charges on capital correspond more closely to levies made to the cost of power, i.e., interest, straight-line depreciation, and Ontario Hydro's statutory sinking fund.

It is apparent that, regardless of whether the figures are based on 1976, 1985, or 1995 costs, at low capacity factors combustion turbines are least costly, at mid-range capacity factors coal-fired units are least costly, and at high capacity

factors, nuclear units are least costly. This situation prevails whether the data are based on long-run costs or related to levies made to cost of power. Using the long-run costs leads to nuclear units breaking even with fossil-thermal units at lower capacity factors, and fossil-thermal units breaking even with combustion turbines at lower capacity factors.

Figures 6.1-10 and 6.1-11

These show the total annual cost per kilowatthour sent out. They use the data of Figures 6.1-8 and 6.1-9, but express it per kWh instead of per kW.

Figures 6.1-8 to 6.1-11 show the estimated annual costs of the stations during their first year of operation. The complete cost comparison of the alternatives must encompass all their costs throughout all the years of their useful lives. This comparison is given in Figure 6.1-12.

Figure 6.1-12

This shows the accumulated year by year expenditures for several alternative installations of gas turbines, fossil-steam, and CANDU nuclear stations. It shows at year zero the capital cost of the station, and the additional year by year expenditures for operation, maintenance, and fuel.

Figure 6.1-12 displays the accumulated expenditures for all the alternatives, based on 60% annual capacity factor.

The diagrams run for 30 years. The actual useful life of the alternatives may prove to be greater than 30 years.

Part I of the figure shows undiscounted accumulated expenditures. Part II shows them discounted to the year in which the first unit comes into service. It is the latter diagrams which form the appropriate inputs for cost comparison, as discussed in Section 10.0 of this report.

Part II of the figure clearly shows that nuclear generation leads to higher accumulated discounted expenditures in its early years of operation, but thereafter much lower accumulated discounted expenditures. In the long run, it clearly leads to lower costs than fossil-steam capacity.

All the costs shown in the preceding figures are the costs at the generating stations per kilowatt sent out. They exclude the costs of transmission and the costs of reserve capacity. Transmission and reserve costs are relatively unaffected by whether the units are fossil-steam or nuclear, but they can be affected by the size of of the units and their location in the province.

Figure 6.1-13

Figure 6.1-13 indicates in a general way the reserve generation requirements related to the use of different sizes of units. The figure shows the effect of adding a series of units to the Ontario Hydro's East System generating stations now in-service or under active design and construction, plus the Bruce B and Darlington Generating Stations.

The figure shows the required additional generating reserves, expressed as a percent of the additional load that can be supplied with a specified target reliability (i.e., Loss of Load Probability of 1/2400, 1/240 and 1/24) by the addition of the series of units of the same size.

The middle column of diagrams in Figure 6.1-13 is based on the adjusted forced outage rates shown in Figure 6.1-5; but it uses the "mature" rates which apply for the 4th or 5th year of operation. The outer columns of diagrams show the effects of outage rates 75% and 125% of those in Figure 6.1-5.

It is clear from the Figure that higher reserves are required, if:

(a) higher reliability levels are required (e.g. loss of load probability of 1/2400 instead of 1/24);

(b) higher forced outage rates are used (e.g., 125% instead of 75% of the rates estimated in Figure 6.1-5); and

(c) larger unit sizes are used (e.g., 1250 MW units instead of 200 MW).

Figure 6.1-14

Using the data of Figure 6.1-13 and further computations, the required additional reserves for a major series of unit additions were roughly estimated at the values shown in Figure 6.1-14. With such data, it becomes possible to adjust the cost comparisons given in Figure 6.1-12 to reflect the effect of the different reserve requirements of different units.

Figure 6.1-15

This shows, for various annual capacity factors, the accumulated expenditures at year 30, discounted to 1985, for fossil-steam and CANDU nuclear units coming into service in 1985. Two sets of curves are included:

A: The cost expressed in dollars per kilowatt of load-meeting capability. This is the cost adjusted to reflect the effect of the different reserve requirements of different units, as noted in the preceding paragraph.

B: The costs per kilowatt sent out of the generating stations. This is the cost unadjusted to reflect the reserve requirements.

By comparing the "A" and "B" curves one can see that the inclusion of the effect of reserve requirements diminishes the advantages of the larger units, whether they are fossil-steam or nuclear.

One can also see that the annual capacity factor has a significant bearing on the cost comparison of fossil-steam and nuclear generation.

Taking account of the reserve requirements:

- at 40% ACF, nuclear units are lower in cost than fossil-steam only at sizes above 750 MW.

- at 60% ACF, nuclear units are lower in cost above 300 MW.

- at 80% ACF, nuclear units are lower in cost above 250 MW.

- regardless of ACF, there is a clear advantage in using larger generating units, up to about 750 MW for fossil units and 1000 to 1250 MW for CANDU nuclear units.

However, Figure 6.1-15 is based on a LOLP of 1/2400, and AFOR's equal to 100% of the forecast values. Figures 6.1-14 shows that the reserve "penalty" associated with larger units becomes lower if lower LOLP's are used, and/or if lower AFOR's are used.

This illustrates in general terms the underlying factors affecting the cost comparison of alternative types of units and sizes of units. There may be substantial cost advantage in using larger units.

However, the data can only be used as a general indication of costs. In practice, more elaborate studies must be done, to include such effects as:

(a) various rates of load growth;

(b) the cost of providing operating reserves whose magnitude is increased as unit size is increased;

(c) the cost of bulk transmission and interconnection requirements which may increase as unit size is increased;

(d) problems in scheduling planned maintenance;

(e) larger units may not match year-by-year growth as well as the use of smaller units;

(f) different nuclear energy-production capability of programs with different sizes of nuclear units;

(f) more accurate estimates of the costs and reliability of alternatives;

(i) the higher outage rates of generating units during their period of immaturity;

(i) estimates of the capability of manufacturers to provide equipment for larger sizes of units, etc.

Ontario Hydro's practice has been to build a series of units of about the same size and to review from time to time the net benefits arising from switching to a larger size. When the net benefits favour a switch, another series of larger units is built. Ontario Hydro proposes to continue this practice, and switch to larger units when this is advantageous.

In recent years, Ontario Hydro has concluded that future new stations for its East System in the 1980s should comprise 500 MW and 750 MW fossil-steam units and 850 MW CANDU nuclear units. However, further cost studies may indicate that larger nuclear units should be installed in this period. Cost analysis indicates that the nuclear units would operate largely in the base load mode, and fossil-steam units in the intermediate or peaking mode of operation.

The effect of transmission requirements upon the cost assessment is discussed in Section 12.0.

T. References

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6.2 FUELS SUPPLY

Contents

FIGURES (Bound in Volume 2)

6.2 Fuels Supply

A. Introduction

This section deals primarily with the requirements of Ontario Hydro's East and West Systems for fossil and nuclear fuels, and the factors that enter into the establishment of an economic and responsive fuels supply program. The various illustrative tables included in this section are based where relevant on Ontario Hydro's Generation Development Program LRF 43P. In September, 1975 this program was considered to be the most probable of the many possible future programs. It was based on meeting the most probable future loads that were forecast in 1975; and it included a relatively high rate of development of nuclear capacity.

B. Strategy

Fuel supply is complex and demanding in relation to objectives and constraints. Four factors are fundamental - fuel quality, security of supply, cost, and flexibility in quantities deliverable. In addition, environmental considerations and conservation of non-renewable resources, together with the social and economic goals of the community help shape the evolving structure of a viable and responsive fuels program. This section attempts to provide an insight into many of these individual elements and into the overall form of the fuels supply program.

Three principal conclusions that result from current evaluations of planned future fuel needs as well as the considerations noted above are:

(a) Because of their scarcity and cost, oil and gas will not be proposed as the primary fuels for use in new fossil-steam generation developed after completion of the oil-fired station at Lennox GS and the proposed oil-fired generating station at Wesleyville.

(b) The use of coal for additional generation is planned, but on a limited basis, because of concerns related to coal supply expansion, security, increasing costs, and air quality.

(c) Primary fuel reliance for the future will be placed on indigenous supplies of uranium, provided that capital requirements for new nuclear generating stations can be met.

C. Future Requirements

The forecast of annual fuel usage in commercial units is given in Figure 6.2-1, based on Program LRF43P. The quantities of fuel required are on a massive scale by 1980 and for uranium and coal these requirements continue to expand past 1980.

Insofar as residual oil and natural gas are concerned, the forecast usage stabilizes at 1980 levels, thus limiting the demands of the power system on these relatively scarce resources.

Figures 6.2-2 and 6.2-3 are consistent with Figure 6.2-1. They provide a forecast of energy distributions by source: fossil fuel, uranium, hydraulic generation and purchased energy. The presentation is by relative output expressed in electrical units and by percentages, respectively.

Both tables illustrate Ontario Hydro's proposal in Program LRF43P that uranium and coal will become the preponderant sources of its electrical output, providing by 1990 some 82% of the total energy. Residual oil will account for only 3% and natural gas only 2% of the output forecast for 1990. Clearly, in terms of demands on limited oil and gas supplies, the projected trends represent a responsible and logical response.

D. Sources of Fuel

Coal

Ontario Hydro has long-term contracts with United States coal suppliers in Pennsylvania and West Virginia. At present, Ontario Hydro has under contract a nominal 10,250,000 tons per year as shown below.

U.S. Tons Per Year		Expiry Date
6,000,000	Consolidation Coal Company	1986
2,500,000	Eastern Associated Coal Corporation	1984
1,750,000	Various Companies	1979-80

It is expected that most of these contracts will be renewed or replaced as they expire.

Deliveries of coal under a further contract, with the United States Steel Corporation, are scheduled to begin in late 1976 and should reach a rate of 3 million tons per year by December 1978. This contract will provide a total of 90 million tons of coal over a thirty year period.

Consumption of Western Canadian bituminous coal is expected to be about 4.0 to 6.0 million tons per year by 1980. Ontario Hydro is currently assessing likely sources and is contracting with potential suppliers.

In addition to the bituminous coal, Ontario Hydro plans to use smaller quantities of sub-bituminous coal and lignite from Western Canada. These coals will largely be used for new generating stations designed to use them as the primary fuel.

Eastern Canada is not considered a significant source of future coal supplies because at present supplies are very limited and there is no assurance of supplies in the long-term.

Offshore coal represents a possible source, but does not appear at this time to be competitive in cost with United States coal nor comparable in security with Canadian coal.

Oil

Ontario Hydro has contracted with a Quebec refinery utilizing Venezuelan and Middle Eastern crude for a supply of residual fuel oil. The contract, for 5 million barrels of oil per year, expires in 1979. In addition to the supply of residual oil originating from foreign crude, Ontario Hydro and Petrosar Limited of Sarnia, Ontario have exchanged letters confirming arrangements whereby Petrosar Limited is to supply 7.3 million barrels per year of low-sulphur residual fuel oil using Western Canadian crude oil as the feedstock. The supply contract would extend for 15 years from 1977 through 1991 and be renewable for 3-year periods thereafter.

Natural Gas

Ontario Hydro has a contract with Consumers' Gas Limited for the supply of a nominal 49 billion cubic feet of natural gas per year until November 1981. It is presently used at the Richard L. Hearn generating station which has four 100 MW units fuelled solely with gas and four 200 MW units which can be fuelled with gas or coal.

Supplies of Arctic gas are likely to become available in the early 1980's, thus offsetting anticipated declines in the movement of Alberta gas supplies to Ontario.

Uranium

Canada has large reserves of uranium currently estimated at 400,000 megagrams, and a large portion of these reserves are in Ontario. Canadian proven reserves that have been set aside for Canadian use are sufficient to provide 30 years' operating life for Canadian stations in operation, stations under construction and committed, and those planned to be committed through 1985. The use of these reserves and additional reserves that may be found depends on the rate at which uranium production capability is developed. This matter is dealt with later in this section.

During the next ten years, Ontario Hydro proposes to increase its installed nuclear capacity substantially, with a resultant increase in the requirements for nuclear fuel. Existing contracts will meet almost all of Ontario Hydro's requirements for the period 1976-1979 and part of its needs through to 1985. From 1975 to 1979 deliveries will total 2,708 megagrams of uranium, and from 1980 to 1985 deliveries covered by current agreements total 3,920 megagrams of uranium. Over the past two years Ontario Hydro has been negotiating contract terms with Canadian producers for additional supplies.

Thorium

Thorium has potential future use as a nuclear fuel in Candu reactors. Canada's reserves are conservatively estimated to exceed 80,000 megagrams of thorium, and appear adequate to meet Canada's requirements over any reasonable planning horizon.

E. Transportation Logistics

Coal

Currently, virtually all coal comes from the United States and is transported by unit trains throughout the year to terminals at Conneaut and Ashtabula on the south shore of Lake Erie. During the lake shipping season, this coal is moved by self-unloading lake boats to stockpiles at Ontario Hydro's coal-fired stations.

Planned coal supplies from Western Canada will be moved by unit trains to stations in Northwestern Ontario. Coal from Alberta and British Columbia destined for use at existing stations in Southern Ontario will be moved by unit train to a terminal at Thunder Bay for storage, and trans-shipped by lake ships.

Because shipping is shut down during the winter non-shipping period (December 31 to April 1), the stockpiles at the generating stations must provide for forecast usage during the winter period as well as possible increases beyond this due to

such conditions as increased power demands, reduced generation at other types of stations due to outages, delays in the start of coal shipments due to weather or strikes, etc.

In both cases, above, combined shipment by rail and ship to Southern Ontario stations is more economic than rail alone. Consideration has also been given to the use of slurry pipelines to transport Western Canadian coal but these do not appear economic at throughputs of less than ten million tons per year.

Technological developments such as coal gasifications, solvent refining, etc. could impact on transportation logistics, but these are not expected to have any substantial effect before the mid 1980's.

Residual Oil

Currently, residual oil is moved by rail from a Quebec refinery and the same mode may apply to shipments from Petrosar in Sarnia. However, other alternatives are under active study including the use of lake tankers, pipelines and interconnections with the Interprovincial Pipeline. Transportation logistics must be able to accommodate a wide range of throughputs since oil usage under contingency conditions can, for an extended period, be two or three times normal usage. Thus, to assist in meeting sustained high output requirements as well as for normal operating reasons, substantial oil storage is provided at oil-fired generating stations.

Natural Gas

Gas supply is delivered to the Hearn Generating Station by a special connection to the Consumers' Gas system which in turn is supplied by the Trans Canada Pipelines system. Since all the natural gas used is produced within Canada and will be moved by pipeline, no alternative transportation mode is under consideration. Consumers' Gas has substantial underground gas storage in Ontario, and Ontario Hydro's consumption pattern meshes well with Consumers' storage, security and operating needs.

Uranium

Since the physical quantities of uranium fuel are relatively small transportation logistics are not significant. However, the processing and manufacturing operations involve several months' lead time from production of yellowcake (U308) at the mine to delivery of fuel bundles. A backup reserve of finished fuel bundles is maintained to provide operational flexibility and economy as well as security of fuel supply for the nuclear stations.

F. Security of Supply

Until recently the required security of supply of fuels could be adequately assured by entering into contracts for the necessary quantities with established commercial suppliers. However, with the changes that have occurred in the fuel industry in the past two years, the options open to fuel consumers with the existing infra-structure have altered greatly. Increasing governmental interventions, both domestic and foreign, in the control of fuel resources have severely limited the ability of commercial suppliers to make long-term commitments. Also, with the development of different policies in various jurisdictions (provincial, federal, foreign) and with increasing inter-jurisdictional disputes on resource regulations, prudence dictates that security considerations weigh heavily in developing a fuels supply program.

These structural changes in access to fuel supplies have created the need for new approaches in ensuring fuel supply, not only for Ontario Hydro's existing generating stations whose operating life is expected to extend over 30 to 40 years, but also for future stations.

Figure 6.2-4 illustrates to some extent the dependence of Ontario's power system on Canadian and foreign resources of energy and fuel. The proportion of Ontario's electricity supply relying on Canadian resources was 63% in 1970, 71% in 1975, and is forecast at about 72% in 1980 and over 82% in 1990.

Security is sought in a number of ways, including diversity of fuels, diversity of fuel sources, contractual arrangements with well-established and responsible suppliers, ensuring adequate fuel reserves and production capabilities and reliance on Canadian resources where feasible. Security of fuel supplies is linked as well to overall system planning policies which can enhance fuels security through the choice of appropriate sytem generation facilities, i.e., nuclear stations vs coal-fired stations.

Coal

Reliability of supply of existing U.S. coal supplies is considered good, but can be influenced by various considerations including the ability of U.S. mines to produce sufficient volumes of coal to meet both domestic and export demands. It is not planned at this time to base new generation on additional long-term U.S. coal supplies prior to the mid-1980's. This is because of the expected increases in U.S. demand for its own coal as U.S. utilities switch from oil and gas to coal, of the associated sensitivity to increased exports, and of U.S. concern for security of supply in their own country.

Arrangements are in progress to develop a long-term Western Canadian coal supply to supplement U.S. deliveries. Experience gained during recent test programs has confirmed the techno-economic and environmental constraints associated with Western Canadian coal. Once agreements for Western Canadian coal have been signed and experience gained on the production and logistics systems, the long-term reliability of supply should be excellent. Short-term interruptions of supply as a result of operational problems could still develop as with other fuel sources.

Oil

The supply reliability of residual oil is better than that of crude oil because of the greater demand for crude oil fractions used in transportation, petro-chemical feedstock, etc. However, reliability of all domestically produced oils will depend, over the long-term, on the actions of governments in encouraging the development of additional sources of oil (either frontier oil or the tar sands).

Currently, Hydro's oil supply program envisages primary reliance for residual oil on an Ontario refinery (Petrosar) supplied with crude from Western Canada, and a Quebec refinery (Golden Eagle) supplied with foreign crude. Spot purchases of residual oil, or crude if necessary, can provide additional supplies. Both oil-fired stations, Lennox GS partially in operation and the proposed Wesleyville GS, have been designed to store and use either residual or crude.

Should oil shortages develop, it is National Energy Board policy that Canadian consumers will take precedence over export commitments for domestically produced and/or refined oil.

Reliability of offshore oil will be dependent on the policies of the governments of producing countries. At the moment, the marketing structure is such that no assurances can be given for long-term supplies. However, total interruptions of foreign oil supplies if they were to occur would most likely be of relatively short duration. Limited cutbacks of foreign supplies are more likely than total interruptions and these cutbacks could be maintained for extended periods.

Natural Gas

Because of its low priority as a boiler fuel, of impending shortages at least into the 1980's, and of the politically sensitive nature of supplies, natural gas is not currently being considered by Ontario Hydro as a primary fuel for new generation. However, Ontario Hydro has a firm contract providing for the supply of 49 Bcf per year up to November 1981.

Development of Arctic gas reserves and construction of a pipeline from the Mackenzie delta in the early 1980's and similar development of Polar gas would help ensure the continued availability of the gas supply.

Uranium

In the case of uranium the situation is unique. Of the several fuels, uranium is the only one which is present in Ontario in quantities large enough to meet the major portion of Ontario Hydro's nuclear requirements for an extended period.

However, the forecast demand for uranium both in Canada and on a world scale appears to greatly exceed estimated production capabilities in the long-term. Shortages could develop in the middle to late 1980's (see Figure 6.2-5). In this situation, and since exploration activity in Canada has been at a relatively low level, Ontario Hydro has deemed it advisable to participate financially with experienced mining companies (e.g., Shell Canada, Amok Ltd.) in the hope of stimulating expanded exploration by all interests. New Canadian uranium finds would provide further security in meeting uranium needs over the long-term. Producibility from new finds will be limited by extended lead times of 8 to 12 years between the start of exploration and the start of production.

Present plans call for most of Hydro's future load growth to be supplied from nuclear power generation. Thus the importance of uranium as Hydro's major fuel resource in the long run makes it necessary to secure access to substantial uranium deposits in Canada with production potentials extending into the 21st century.

G. Flexibility

Flexibility in fuel supply arrangements must be provided to mesh with the fact that actual usage does not usually match forecast usage. Thus, the fuel supply program must include flexibility provisions to permit increasing or decreasing fuel deliveries from forecast levels.

The absolute amounts of fuel actually required as well as the relative mix of fuels is affected by many developments and contingencies. These include year-to-year and long-term deviations of the actual loads from the loads forecast, changes in system generation expansion programs, reductions in generation due to station outages, variability in hydraulic resources, variability in purchases and sales of energy, power transmission limitations, variations in station performance, fuels availability and logistic problems, and other factors. Thus, the development of an adequate fuels supply program is

not simply to arrange for supply of fixed quantities of fuel to meet forecast requirements but also to provide a high degree of flexibility in the actual quantities delivered so that they can match changing needs.

Flexibility is provided through the use of stockpiles (coal, oil, uranium), through contracts with provision for reducing or increasing deliveries, through short-term or spot purchases, through sales of surplus fuel, through fuel substitution (i.e., running an oil-fired station instead of a coal-fired station), and through a mix of fuel supply contracts with different termination dates.

d. Fuel Quality

Fuel quality here encompasses three elements:

(i) operating suitability for use in Ontario Hydro's generating stations

(ii) effects on the environment related to the fuel, and,

(iii) effect of quality requirements on cost of fuel. costs.

Coal

Ontario Hydro's existing coal-fired stations were designed to burn high-BTU, medium - sulphur, high-volatile coals from Ohio, Pennsylvania and West Virginia. Use of other types of coal can reduce station output, imperil human and equipment safety, and adversely affect air quality. Thus coal for these stations must meet fairly precise specifications to be acceptable. In order to be able to burn Western Canadian coal successfully in existing stations, it is planned to use a blend of U.S. and Canadian coal.

New stations can be designed to burn Western Canadian coal alone, and such stations are under construction and proposed for Northwest Ontario.

Residual Oil

Residual oil supply must meet operating specifications, and must in particular meet sulphur content limits for environmental reasons that can vary from station to station, and that can vary with time depending on station output and weather conditions. Thus the basic long-term supply of residual oil is specified to have a sulphur content of less than 1%. This permits blending with other oils which may be obtained to meet higher electricity demands without exceeding air quality guidelines. The cost of such low sulphur residual oil is in general above that for oil with higher levels of sulphur.

Natural Gas

Gas delivered to Ontario presents no quality problems from an operating standpoint, or with respect to sulphur or particulate emissions. It is however a premium fuel which over any extended period will likely be more expensive than coal or oil.

Uranium

Fuel bundles containing uranium are a manufactured product meeting specific Ontario Hydro requirements, and thus do not raise any quality issues of the kind that apply to coal and oil.

I. Conservation Aspects

Ontario Hydro, as a producer of electrical energy, is deeply concerned about the continuing availability of all forms of energy and subscribes fully to the need for conservation. Conservation programs should affect the selection, supply and use of primary fuels for the electric power system. For this to be effective, it is necessary to have a clear understanding of the overall aim of the conservation program, and the part that electric energy production should play in it.

Some constraints and factors which must be considered in developing the fuels supply program for the electric system are:

(a) Fuel requirements for existing generating stations

(b) Present and projected environmental targets

(c) Availability of fuels - Figures 6.2-6 and 6.2-7 show potential medium-term shortfalls in Canadian oil and natural gas

(d) Security and deliverability of fuel supplies

(e) Level of flexibility necessary to respond to changes in fuel supply and demands

(f) Cost considerations

(g) Electricity transmission capabilities.

Two areas in which Ontario Hydro's program conserves fossil fuels are noted below.

Nuclear-Based Generation

Ontario Hydro's proposed commitment to the CANDU nuclear system, to the extent that about two-thirds of future thermal generating capacity is proposed to be nuclear with the balance coal-fired is an important form of fossil fuel conservation. If the power system had no nuclear stations and all other constraints remained the same, then by 1990 in order to meet the demand, Ontario Hydro would have had to install additional fossil-fired generation which would consume the fossil-fuel equivalent of 53.7 million tons of coal per year. Figure 6.2-8 illustrates this point.

Generation Based on Oil and Gas

In order to maintain flexibility to react to unforeseen changes and to meet environmental guidelines, Ontario will have a continuing need for oil and natural gas. Nevertheless, because of their relative scarcity and costs, the joint contribution of oil and gas to system generation does not increase. Figure 6.2-2 shows that it declines from 12,800 GWh in 1980 to 11,000 GWh in 1990 despite system expansion. Furthermore, residual oil rather than crude oil will generally be used in the power system to conserve the light and middle fractions of crude which are valuable for other uses.

J. Cost Factors

Methodology

The methodology of developing expected fuel costs is covered in Appendix 10-C. However, it should be emphasized that in the period under consideration, i.e., beyond 1982, fuel cost projections should be viewed with caution. This is not because the methodology is unreliable but because the primary fuel industry is fraught with uncertainties, primarily politically induced. Any error due to methodology, even in a short-term forecast, can be completely obliterated by a single political decision.

Figure 6.2-9 provides a projection of possible fuel cost trends, but these are subject to the uncertainties noted above. These projections indicate that uranium and coal are likely to improve their cost advantage over oil and gas. This factor together with their greater availability will maintain their preferred rank for power generation.

Security and Flexibility

For security, economic and other reasons, it is Ontario Hydro's preference to enter into long-term contracts (five

years or longer) for most of its fuel supply. To a degree, this procedure insulates Ontario Hydro from severe fluctuations in the price of fuels.

However, in order to maintain an adequate level of flexibility to meet changing demands for fuel, spot purchases and short-term contracts are also made.

Since the power system has a mix of generating stations (nuclear, coal, oil, gas, hydraulic, etc.) with different efficiencies, and these stations are interconnected both within Ontario and with adjacent utilities there is an inherent opportunity to minimize total system fuel costs by judicious selections of station outputs and fuels choices as well as by appropriate sales and purchases of fuels and energy. These opportunities are taken whenever feasible as a normal part of operating and procurement practice.

Environmental

Increasingly stringent environmental regulations have and will continue to have a significant influence on fuel costs.

Power system use of natural gas and low-sulphur residual oil at some locations is predicated on environmental regulations.

The use of low sulphur Western Canadian bituminous coal, blended with U.S. coal, is predicated in part on meeting air quality regulations at existing stations without installing expensive and unproven scrubbing systems. However, this will raise the average combined fuel cost because Western Canadian bituminous coal delivered to Southern Ontario is substantially more expensive than coal from the U.S.

Availability

The cost of uranium supplies has also been escalating in concert with those of fossil fuels and supported by an increasingly imbalanced supply/demand relationship as uranium production capability fails to keep pace with planned nuclear capacity.

The most important factor affecting fuel costs in the long-run is physical availability. With increasing demand for fuels, incremental supplies will be obtained from resources which, as a general rule, will be higher cost than those already in production. Thus average unit fuel costs will continue to rise in real terms in the foreseeable future pending revolutionary technological breakthroughs in forms of energy production and use.

K. Environmental Considerations

Fuel characteristics are only one element in determining the effect of generating stations on the environment. Station location, station design, weather conditions, operating procedures, etc. are factors as well. However, fuel characteristics are important, and in particular the sulphur and ash content of fuels provides a major indication of potential levels of air pollution.

Ontario Hydro's proposed generation program provides for a mix of different fuels to be used in producing electricity. The total fuel quantities, the relative proportions of the different fuels and their properties change over the forecast period. All of these factors impinge on the absolute and relative sulphur content.

Figure 6.2-10 illustrates trends in sulphur content of Ontario Hydro's fossil fuels, actual in 1970, and forecast to 1995. In this table, residual oil and natural gas are included as equivalent tons of U.S. Coal. Figure 6.2-10 shows the following trend. From 1970 to 1995, the fossil fuel consumed increases four-fold but the total sulphur content increases only two-fold. The sulphur proportion of fossil fuels reduces from 2.5% to 1.3%.

The effective reduction in the proportion of sulphur content would be shown as far greater if due allowance were made for the impact of the nuclear generation program in limiting the total consumption of fossil fuels, and thereby greatly limiting the emission of sulphur and particulates.

The following list notes some of the measures taken by Ontario Hydro which have directly or indirectly reduced sulphur content of fuels or which have reduced ground level concentrations:

(i) Purchases of low-sulphur U.S. coal, e.g., U.S. Steel coal with 1.7 to 1.8% sulphur.

(ii) Utilization of natural gas at Hearn GS.

(iii) Long-term arrangements for low-sulphur residual oil.

(iv) Development of the Western Canadian coal supply program.

Related design and operating policies and practices which help maintain air quality include:

(v) Establishment of an extensive nuclear generation program.

(vi) Installation of high stacks at fossil-fired thermal stations.

(vii) Use of pollution potential forecasts in operating system generation to reduce concentrations of pollutants.

L. Background Documents

(1) Ontario Hydro, Submission to the National Energy Board on Natural Gas Requirements - September 1974.

(2) Ontario Hydro, Submission to the National Energy Board on Oil Requirements - April 1975.

(3) "Sulphur Content in Relation to Fuels Supply Program 1979- 1990". - W. Shelson, Ontario Hydro - June 18, 1975.

(4) "Hydro Signs Long-Term Coal Contract" (with United States Steel Corp.) - Ontario Hydro News Release - March 1, 1974.

(5) "The Role of Coal in Thermal Generation". - M. Nastich, Ontario Hydro - Presented to 27th Canadian Conference on Coal, Vancouver - September 22, 1975.

(6) "Coal Transportation on the Great Lakes". - J.L. Cooke, Ontario Hydro - Presented to Institute of Marine Engineers and Society of Naval Architects and Marine Engineers, Toronto - March 14, 1973.

(7) Ontario Hydro, Submission to the Alberta Energy Resources Conservation Board on Coal Valley Mine Project - July 1975.

(8) "Uranium Exploration Needed Says Ontario Hydro" - Ontario Hydro News Release - October 24, 1975.

(9) "An Energy Policy for Canada" - Canada, Department of Energy, Mines and Resources - 1973

(10) "Energy in Ontario - The Outlook and Policy Implications" Advisory Committee on Energy, ONTARIO - 1972

(11) "Canadian Natural Gas - Supply and Requirements" - National Energy Board - April 1975.

(12) "Canadian Oil - Supply and Requirements" - National Energy Board - September 1975.

(13) "U3O8 - An Analysis of Demand and Supply" - C.R. Lattanzi, Annual Meeting of World Nuclear Fuel Market, Washington, D.C. - September 1975.

6.3 HEAVY WATER

Contents

6.3 HEAVY WATER

A. Introduction

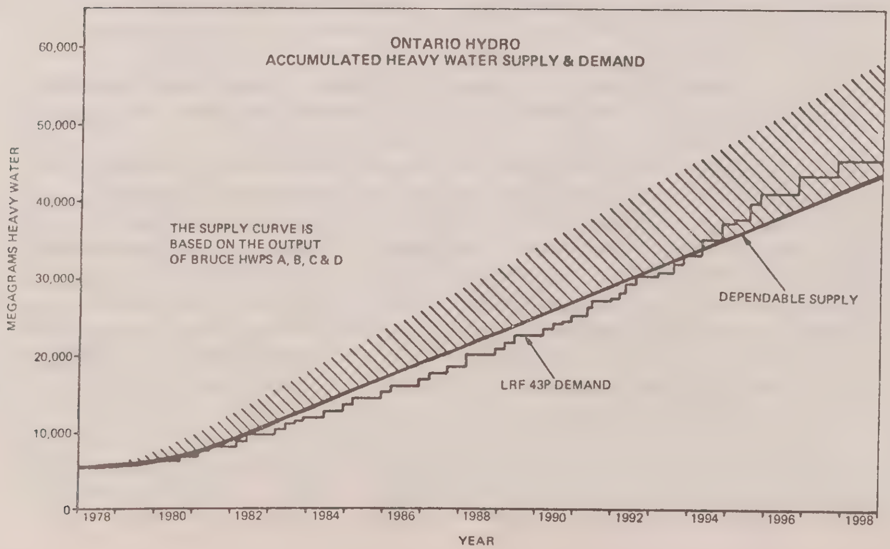
This section summarizes the estimated heavy water demand of the CANDU-PHW reactors included in Ontario Hydro's Generation Development Program LRF 43P. It compares this demand with the possible supply from heavy water production plants in Ontario, comments upon safety aspects, and outlines Ontario Hydro's position on future needs for further heavy water production facilities.

B. Heavy Water Demand

Heavy water is used as the moderator and heat transport fluid in the CANDU-PHW reactor. CANDU-PHW reactor units on the Ontario Hydro system require an initial charge of from 0.8 to 1.0 megagrams of heavy water per installed electrical megawatt of output capacity. During the course of operation these reactors require additional amounts of heavy water to replace minor losses.

Any forecast of Ontario Hydro's long term accumulated demand for heavy water is dependent on the number and size of additional CANDU reactors proposed in the long-term electric power system expansion program.

The anticipated accumulated demand by Ontario Hydro for heavy water corresponding to the Generation Development Program LRF 43P is shown in the following figure.



The demand curve shown in the figure assumes that all the nuclear generation included in LRF 43P is of the CANDU-PHW type and includes allowance for minor losses of heavy water during operation of the reactors. The demand shown in the figure includes no allowance for increases in demand due to major losses or major downgrading in quality of heavy water during the operation of the reactors.

C. Heavy Water Supply

Heavy water does not trade freely on the open market,and it is not available in quantity from sources outside Ontario. Ontario Hydro is currently arranging to secure its foreseeable heavy water needs via ownership and operation of Bruce Heavy Water Plants A, B, C and D. Each of these heavy water production plants has a design production capacity of 96.6 kilograms per hour, or 846 megagrams per year, at the required finished heavy water isotopic concentration of 99.8%.

Bruce Heavy Water Plant A went into service in 1973. Bruce Heavy Water Plants B, C and D were scheduled under LRF43P to be in-service as follows:

Bruce HWP B - February 1979
Bruce HWP D - July 1979
Bruce HWP C - March 1980

BHWP-A, B, C and D all operate on the Girdler-Sulphide (G-S) process.

All heavy water supply forecast data is extremely sensitive to the assumed long-term production capacity factors. Since there is no substantial accumulation of operating experience with heavy water production facilities in Ontario, there is considerable uncertainty in any forecast data, and actual achieved results may be better or worse than the forecast.

Current anticipated accumulated supply of heavy water to Ontario Hydro from BHWP A, B, C and D is also shown in the figure on page 1. The hatched area on the curve represents the possible range of accumulated supply. The lower boundary of the range is marked by the dependable accumulated supply curve. Dependable supply is based upon a 60% maturity capacity factor for the heavy water production plants BHWP-A, B, C and D. Program planning is aimed at satisfying accumulated demand with dependable accumulated supply, because there are no significant supply alternatives.

The supply curve indicates that unless actual maturity production capacity factor substantially exceeds 60%, it will be necessary to develop additional heavy water production plants to meet demands after 1993.

D. <u>Safety Considerations</u>

The Ontario Hydro heavy water production plants contain substantial quantities of hydrogen sulphide gas which is toxic. To meet its responsibility with regard to public safety, Ontario Hydro incorporates features into the design and operation of its heavy water production plants to prevent or mitigate the consequences of the accidental release of hydrogen sulphide. These features include:

(i) the provision of reliable process systems and equipment that are designed and constructed to petrochemical industry standards and which will also meet the regulatory codes and standards, and thus will normally keep the operation within predetermined safe limits.

(ii) the provision of isolation circuits to minimize the release of hydrogen sulphide should a leak develop in a pressure boundary.

(iii) regular inspection of piping and pressure vessels to ensure that no significant deterioration is occurring.

(iv) Well trained operating and maintenance staff to ensure that all systems are kept in a reliable condition, and

(v) the establishment of emergency procedures and the provision of operating and maintenance staff trained and equipped to deal with emergency situations should any occur.

The federal Atomic Energy Control Board (AECB), has authority under the Atomic Energy Act to license and regulate all nuclear facilities. This includes Heavy Water Production Plants. The AECB issues construction licences for Heavy Water Construction Plant when it is assured that all relevant safety regulations are being met. It continues to monitor progress as design and construction proceed to ensure that detailed design meets all safety criteria. Prior to operating the plant, the AECB will have reviewed the complete design in detail, including analyses which describe plant behaviour under a range of very severe accident conditions.

The AECB also receive advice from a Safety Advisory Committee, set up for each heavy water production plant project. This committee consists of federal, provincial and local experts in various fields. This committee must make recommendations on

the suitability of any heavy water production plant before it can be constructed or operated

When the plant is ready for operation, an operating licence is issued by the AECB which stipulates conditions under which the plant is to operate to ensure continuing safety during its operating lifetime. Once a facility is in operation, AECB staff officers inspect and monitor plant performance to ensure adherence to the stipulated conditions. The AECB staff officers receive annual reports which describe plant operation and they can demand reports on any event or occurrence that they consider to be significant or unusual.

E. Alternative Processes

Although there are other processes for separating heavy water from ordinary water, none of them is currently commercially viable, and there is little prospect of commercial application to meet the additional heavy water supply needs after 1993. Therefore any site currently studied for heavy water production plants should be suitable for installation of the G-S process.

F. Position of Ontario Hydro

With the commitment of BHWP-B, C, and D, heavy water needs for at least the next 10 years would appear to have been satisfactorily assured, provided program LRF 43P is followed. The required lead time for new heavy water plants, i.e., elapsed time from commitment to in-service is estimated to be about 5 years on a site already owned by Ontario Hydro, and about 9 years on a site not already owned by Ontario Hydro. To meet the demand beyond 1993, further commitment of heavy water production facilities will not be required until the 1980s.

If the demand for heavy water changes as a result of a generating program change; it may become necessary for Ontario Hydro to adjust the program for heavy water supply facilities taking into account the long lead times inherent in property acquisition, plant approval, and construction. As it may not be possible or desirable to install additional heavy water production capacity at the Bruce Nuclear Power Development, subsequent to BHWP-A, B, C and D, it would be desirable and prudent for Ontario to make provision for heavy water production at another site.

The heavy water supply/demand situation will be reviewed in the event of significant changes to the generation expansion program, or if accumulated operating feedback from Bruce Heavy Water Plants A, B, C and D indicates significant deviation in actual production performance from that currently anticipated.

6.4 Environmental and Safety Aspects of Generating Stations

CONTENTS

6.4 Environmental and Safety Aspects of Generating Stations

A. Summary

This section summarizes the environmental and safety aspects that must be considered in the operation of generating stations after they are brought into service, and in the preparation of Environmental Assessments required to support a proposal to acquire a site for a future generating station and a proposal to install generating facilities upon a specific site.

B. The Development of Environmental Studies and Environmental Assessments

The term 'environment' is used in its broadest sense and encompasses the community, land use, aesthetic and social conditions in addition to physical and biological conditions.

Environmental studies are now carried out during the following three major phases involved in the introduction of a new Ontario Hydro generating facility into the existing system:

- site selection
- site development
- the pre-operational, commissioning and post-operational period.

During the site selection phase an area for possible location of a generating station is established. Next, within this area each potential site that is technically feasible is identified. For each site, the effects on the environment which might arise from future construction and operation of generating facilities at the site are assessed. A comparison of these assessments contributes to the ultimate selection of a site.

During the site development phase, more detailed study is undertaken of the selected site and an assessment is made of the possible influences brought about by construction and operation of a specified type and size of generating station.

During the construction, commissioning and operating periods of a generating station, continuing on-site monitoring is maintained to determine the actual influences of the project on environmental conditions.

The first formal environmental studies at generating stations commenced in 1967 and were confined to studies of effects at operating stations. In 1968, the first program was started at a station prior to operation in order to develop baseline data

against which the subsequent operation of the station could be compared.

Up to 1970, Ontario Hydro had acquired sites with no formal environmental or public participation input to the approval process.

In 1971, following a request from the Ministry of the Environment, Ontario Hydro initiated a program of on-site studies at sites where approval of a project was to be sought. The results of these on-site studies were for incorporation into an Environmental Assessment Document to be supplied to the Ministry and to be used as a basis for approval of the project. Ontario Hydro published its first Environmental Assessment, in 1972, before the Province of Ontario's Green Paper on Environmental Assessment was issued.

In 1972, Ontario Hydro incorporated public participation into its site selection process.

Current procedures involve the inclusion of environmental considerations and public participation at the initiation of the site selection process. Formerly this involvement had not commenced until after several potential sites had been identified.

The procedures of site selection and project approval now come under the provisions of the Environmental Assessment Act, 1975. Ontario Hydro will have issued 7 Environmental Assessments for project approval before the Act is to be applied. These are:

Project	Environmental Assessment Issued
Wesleyville	April 1973
Pickering B	October 1973
Bruce B	February 1974
Bruce HWP,B,C,D	February 1974
Thunder Bay Extension	May 1974
Darlington	April 1975
Atikokan	April 1976

It appears that the provisions of the Act will be met by two separate Environmental Assessments - the first leading to the selection of a new site, the second leading to the installation of specific generating facilities on the site. Discussions are currently being held with the Ministry of the Environment on the specific content of each of these documents. One site selection process, which will fall under the provisions of the Act, is now taking place in the area of the North Channel of Lake Huron.

Because of the emphasis on thermal power generation during recent years, no approvals have yet been sought for hydraulic generating stations.

C. Health and Safety Aspects of Nuclear Stations

Ontario Hydro nuclear generating stations must meet legislated standards for their impact on the health and safety of the public and operating staff and for their impact on the environment. The prime legislation dealing with the operation of nuclear facilities is the Atomic Energy Control Act and Regulations (see Reference 6.4(1)) under which the Atomic Energy Control Board (AECB) has the responsibility for the health and safety of the public as a result of the operation of nuclear facilities. Ontario Hydro must satisfy the AECB that its nuclear generating stations are and will be sited, designed, constructed and operated to conform with the requirements of the Atomic Energy Control Regulations and with such conditions as the Board deems necessary in the interests of health, safety and security. To provide information to the AECB and to show compliance with the requirements, Ontario Hydro submits to the Board the following formal documentation for each of its nuclear generating stations.

- A Site Evaluation Report, issued in support of an application to use a specific site for the construction of a nuclear generating station. Reference 6.4(2) is an example.

- A preliminary Safety Report, issued in support of an application for a license to construct a specific nuclear generating station. The preliminary safety report is updated annually throughout the construction period of the station. Reference 6.4(3) is an example.

- Design and Operating Manuals, to provide confirmation that systems, important in terms of overall station safety, comply with basic principles and requirements specified by the Board on the advice of its Reactor Safety Advisory Committee. References 6.4(4) and 6.4(5) are examples.

- A Final Safety Report, issued in support of an application for a license to operate the specific station.

- A document of Operating Policies and Principles, issued in support of a license to operate the specific station. Reference 6.4(6) is an example.

- A document identifying key permanent staff positions and plans for staffing these positions.

- The station staffing and training plan.

- Reports on commissioning of systems and equipment. Reference 6.4(7) is an example.

- An outline for station radiation protection including Ontario Hydro Radiation Protection Regulations, which must be approved by the Board. Reference 6.4(8) is an example.

- Quarterly Technical Reports, indicating the operating performance of the station including information on (a) unusual events of significance to health and safety, (b) the accounting of prescribed materials, (c) radiation doses to station staff, and (d) radioactive effluent releases. Reference 6.4(9) is an example.

- Timely reports of unusual occurrences which are of significance to health and safety.

In addition to the above documents, Ontario Hydro submits to the AECB for its information and review, many other documents such as design guides, quality assurance procedures and equipment classification documents. The AECB also conducts examinations which station staff must pass prior to being authorized for their positions.

D. Radioactive Emissions and Controls

(a) Emissions to Air and Water

The maximum permissible releases of radioactive material from nuclear generating stations are based on maximum permissible doses for members of the public recommended by the International Commission on Radiological Protection (ICRP) and legislated in Canada by the Atomic Energy Control Act, which is administered by the Atomic Energy Control Board (AECB). (See Reference 6.4(10).) The ICRP is an independent, non-governmental body consisting of internationally recognized experts from many countries and a wide variety of scientific disciplines. Its recommendations have been accepted by the World Health Organization and the International Labour Organization, and are used as the basis of standards prepared by the International Atomic Energy Agency.

These standards have been developed over several decades and are based on numerous studies of somatic and genetic effects of high radiation doses and dose rates. The very stringent public dose standards adopted in Canada, and generally worldwide, are based, conservatively, on a linear extrapolation of dose/effect relations observed at high doses to zero dose, i.e., it is assumed that there is no threshold below which there ceases to be an effect.

Ontario Hydro, in line with the ICRP recommendation to keep doses "as low as is reasonably achievable, economic and social considerations being taken into account", has adopted a design and operating target for annual radioactive releases during normal operation, of 1% or less of those releases corresponding to the public dose standard. (See Reference 6.4(11).) The maximum calculated dose to a member of the public living at the site boundary, resulting from releases at this "target" level, is within the normal variation of natural background radiation, and is indistinguishable from it. This target is being met at our large multiunit power stations. (See Reference 6.4(12).)

The calculation of release limits from dose standards involves a knowledge of meteorology, of environmental pathways and biological concentration factors as well as a number of conservative assumptions regarding the living patterns and behaviour of the limiting group of the general population, which could lead to their receiving a larger radiation dose than average from the effluents of a nuclear generating station. (See Reference 6.4(13).)

Radioactive effluents, in gaseous or particulate form, are released to the atmosphere via monitored station ventilation discharge points. Controlled liquid releases occur via the condenser cooling water discharge.

As a further check on the acceptability of the emission standards, on-going environmental monitoring programs are carried out in the vicinity of nuclear generating stations independently by Ontario Hydro and government agencies. These programs include the sampling of air, water and precipitation, as well as fish and locally produced milk. This serves as a check on the suitability of release limits, and any divergence from expected activity pathways would be detected long before any significant risk to man was posed.

(b) <u>Transport and Storage of Radioactive Wastes (Excluding Spent Fuel)</u>

The radioactive solid byproducts produced in a nuclear generating station can be divided into two broad categories:

- spent fuel, which is technically not considered a "waste" since it contains valuable fertile and fissile materials and which however contain over 99.9% of the radioactive material produced in a nuclear station,

- the remainder of the solid radioactive byproducts, termed medium and low level waste. (See Reference 6.4(14.)

The medium activity wastes consist primarily of filter media, water purification resins and solidified liquid concentrates, and account for over 90% of the radioactivity, excluding spent fuel, that has to be stored. Low level wastes include miscellaneous, and not normally radioactive housekeeping materials such as paper and plastic sheeting, mops, rags, scrap materials and equipment, and used protective clothing. Because of radioactive decay of the predominant radionuclides in the medium and low level wastes, isolation of these wastes from the environment is required for a much shorter period than for the high level wastes associated with spent fuel.

Currently, medium and low level radioactive wastes from Pickering GS A are transported to the Bruce Nuclear Power Development for storage. All shipments of wastes are packaged, loaded and transported according to government regulations that are essentially identical to those of the International Atomic Energy Agency. (See Reference 6.4(15).) These require that the packages be inherently safe, and that even in the event of serious accidents, the escape, if any, of their contents would not result in injurious radiation exposure of the public. The considerable experience that has accumulated in the shipment of radioactive wastes on a world-wide basis provides assurance that the objectives of the regulations are being achieved. (See Reference 6.4(16).)

These medium-to-low activity solid wastes are stored in reinforced concrete structures at a waste storage site within the Bruce Nuclear Power Development site. (See Reference 6.4(17).) Ontario Hydro's practice is to store, not dispose of, these wastes in facilities that primarily depend upon double-barrier engineered features to isolate the wastes from the biosphere. Hydrogeologic features of the waste storage site serve to "back-up" the engineered containment capability. Only solids, not liquids, are placed in storage and no wastes are placed directly into soil.

The waste storage site is subject to ongoing operational and environmental monitoring. Particular emphasis is placed on groundwater and surface water sampling because this represents the major potential pathway for activity escape. These monitoring provisions, which include perimeter sampling wells and subsurface drainage systems, ensure detection of any radioactivity escape from the facilities well in advance of it entering the public domain.

It is recognized that the timespan of concern (more than 100 years) for some of the medium and low level radioactive wastes may be longer than the lifetimes of these storage facilities. Hence, the facilities are considered as interim storage and not a means of "disposal". For this reason, all such wastes are stored only in a retrievable manner. Long-term care of the facilities, including transfer of some wastes to replacement facilities, as necessitated by facility degradation, may be required, and is part of the waste management plan.

(c) Spent Fuel Management

Ontario Hydro's plan for the management of the spent fuel produced by its nuclear generating stations covers four main phases. (See Reference 6.4(18).)

The first phase is to store the spent fuel bundles in water-filled storage bays at the nuclear generating station sites for a period of five years or more. During this time the gamma radiation emitted by the spent fuel and the rate of heat production by the fuel will each have decreased a hundred-fold or more from the levels at one hour after discharge from the reactor.

The second phase of the spent fuel management plan is to ship the spent fuel bundles from the station storage bays to an interim storage facility. Here, the spent fuel will be stored until it is packaged in a form suitable for long term disposal (or until it is reprocessed to recover its plutonium content). It is proposed that spent fuel from all of the Ontario Hydro nuclear generating stations will be stored at a single, central, interim storage facility.

The third phase of the Ontario Hydro plan for management of spent fuel is to package the radioactive waste contained in spent fuel, either intact or with the fissile plutonium removed for further use, in a form suitable for placement in a radioactive waste disposal facility. This will require that the radioactive waste be immobilized by fixation in a glass or ceramic matrix prior to disposal. It is unlikely that plutonium from spent fuel will be recycled for some time since prior extensive investigations and development will be required. Therefore, the central interim storage facility will probably be required for a period of twenty-five years or more.

The fourth phase of the plan for spent fuel management is to place the packaged radioactive waste from the reprocessing plant or the unprocessed spent fuel, into an ultimate disposal facility. This facility will be located

deep underground in a geologically stable strata. The material placed there will be isolated from man's environment, and will be immune to such natural phenomena as recurring ice-ages. Initially the material will be stored in a retrievable mode. Once it has been satisfactorily established that the facility will achieve its long term isolation objective, and the stored material has no potential value to man, the retrievability features will be terminated to provide even greater assurance of its separation from man.

This plan for the management of spent fuel is based on a well established base of technology although its application to spent fuel management has yet to be proven. For example, storage of spent fuel in water-filled pools has been undertaken for about 25 years, laboratory-scale experiments of fixation of radioactive waste have been performed, and a great deal of deep mining technology is in existence. However further work is required in the areas of spent fuel transportation systems, identification of the true potential hazard of spent fuel materials, radioactive waste packaging in a form suitable for ultimate disposal, effect of placement of radioactive wastes for long time periods in host rock, plutonium recovery and recycle, and security and safeguards for preventing the illegal diversion of hazardous material, to conclusively demonstrate the suitability of the plan formulated above.

(d) Transportation of Spent Fuel

To-date in Canada only small quantities of spent fuel have been shipped from the generating stations to other places. These shipments have been few in number and have taken place at irregular intervals. However, with the establishment of a successful nuclear program, Ontario Hydro is planning to start regular shipment of spent fuel around 1985. This will involve shipping the spent fuel from the nuclear generating stations (approximately 1 to 2 shipments per week per station) to the central interim storage site.

Shielded shipping containers weighing tens of tons will be used to transport the spent fuel from the nuclear generating stations to the central site. These will conform to the International Atomic Energy Agency standards, ensuring that even in the event of an accident, the release of radioactivity, if any, would not result in injurious radiation exposure of the public. (See Reference 6.4(15).) It is expected that there will not be an appreciable effect on the environment from the shipping of fuel due to heat, weight, traffic density, accidents,

or an appreciable radiation dose to the public and transport workers.

(e) Nuclear Safety

Ontario Hydro has a responsibility to protect the public and its staff from any potential hazards associated with use of nuclear energy for the production of electricity. To meet this responsibility, Ontario Hydro takes measures during the design, construction and operation of its nuclear facilities to minimize the possibility and consequences of incidents which could result in the release of hazardous material.

For example, Ontario Hydro stations contain reliable process systems which are designed to regulatory codes and standards and which minimize the possibility of incidents that might involve a release of radioactivity. A specially licensed and trained operating and maintenance staff ensure that all systems are kept in a reliable condition. In addition, the stations contain design and operating features to minimize the consequences of any unlikely event which could lead to the release of radioactivity. Among these features are highly reliable safety systems (a) to shutdown the nuclear fission process when limiting operating conditions are exceeded, (b) to remove thermal energy safely from the reactor system, and (c) to provide multiple physical barriers to prevent the release of radioactive materials. The safety provided by these physical systems is augmented by undertaking in-depth analysis of the performance of station systems during postulated extreme accident conditions (see Reference 6.4(19)), by inspection and testing programs to ensure system effectiveness and reliability, and by adopting operating policies that give prime consideration to safety. (See Reference 6.4(20).)

In the event of extremely unlikely emergency conditions, protection of members of the public is enhanced by contingency plans established in conjunction with other federal and provincial agencies (see Reference 6.4(21)) and by the provision of staff equipped and trained to deal with emergency conditions should any occur.

Under the Atomic Energy Control Act and Regulations (see Reference 6.4(22)) the Atomic Energy Control Board (AECB) has responsibility for the health and safety of the public as a result of the operation of nuclear facilities. In meeting this responsibility the AECB establishes limits for radiation doses to the public during normal and abnormal nuclear station conditions. The Board issues licenses for construction and for operation of the nuclear station when they have reviewed the detailed design

information and analysis of postulated accident situations submitted by Ontario Hydro, and are convinced that adequate safety will be provided. Once a facility is in operation, AECB staff officers inspect and monitor plant performance and are kept informed of all safety related events.

The adequacy of these measures to provide protection for members of the public is indicated by the excellent safety record of operating commercial nuclear generating stations. No incident has ever occurred in which a member of the public has received a radiation dose in excess of regulatory limits.

E. Non-Radioactive Emissions and Controls

(a) Air

Atmospheric emissions that may be produced by a fossil-fuelled generating station and which are of public concern are particulates, sulphur dioxide, and nitrogen oxides.

The maximum allowable ground level concentration of certain pollutants resulting from stack gas emissions are specified by the Ontario Ministry of the Environment, either by regulation or by design guidelines. New stations are being designed by Ontario Hydro to conform to these design guidelines which are more restrictive than the provincial standards for air quality as specified in the regulations. Present standards are met by electrostatic precipitation of particulate material, by dispersion of emissions to the atmosphere using high stacks and by using specialized operating procedures. For the great majority of the time, the ground level concentration of pollutants resulting from stack gas emissions is well below the regulatory requirements. However in the future, there may be additional social and regulatory concerns which may require other controls to be considered.

Ontario Hydro has conducted research and pilot plant tests on sulphur dioxide emission control and has also participated with other utilities on similar studies. The great variation in types and quality of fuels that are now having to be considered at fossil-fuelled generating stations creates problems with design and operation of effective emission control systems. Considerable flexibility for application of the appropriate technology is required.

Problems with emissions of other gaseous pollutants such as hydrogen sulphide and nitrogen oxides are under active

investigation at operating stations and at those stations under design. Emissions are being controlled by appropriate modifications to the design and operation of equipment.

An active research program is being carried out to determine the contribution by Ontario Hydro to atmospheric sulphates precipitation in Southern Ontario.

i) Particulates

Particulates are formed largely from the incombustible ash content of a fossil fuel. Some of the carbon in the fuel may not be burned completely in the furnace and this can add to the particulate emissions. After combustion of the fuel, some of the particulates are exhausted to the atmosphere along with the flue gases.

Natural gas has essentially no ash content and burns cleanly so that no particulate matter is produced. Oils have some ash content, of the order of 0-1% by weight and burn less cleanly than natural gas, so that some particulate matter in the form of ash and unburned carbon can be produced. Coals have the highest ash levels and can be difficult to burn, so that production of ash and unburned carbon particulate could be in the order of 10% of the weight of coal burned, assuming Eastern US bituminous coal. About 20% of this ash is bottom ash in the form of clinker, so that about 80% is in the gas stream as particulate or fly ash.

Particulate emissions can be controlled by the introduction of a collection device in the flue gas stream at some point between the furnace, where combustion takes place, and the stack, where the flue gases are dispersed to the atmosphere. Collection devices fall into two classes, mechanical and electrical. Mechanical collection devices may be cyclones or bag house filters. Cyclones direct flue gas flow into a rotational pattern so that the heavier particulate material is separated from the flue gas stream by centrifugal forces. They are, therefore, only efficient at separating relatively large particles and leave the small light particles in the flue gas stream. Typical collection efficiencies are about 70%.

Bag house filters separate particulate matter from the gas stream by passing the gas through a filter cloth. Particulate is retained on the filter cloth and the gas passes through. These devices, though

attaining quite high collection efficiencies of about 99%, again tend to have poorer collection efficiencies with very small particulate sizes, and also suffer significant pressure losses through the filter material, resulting in increased fan requirements. They place constraints on the operation of the unit and maintenance costs are high.

Electrical collection devices are all based on the process of electrostatic precipitation, in which a particle is charged electrically and then attracted to a collection surface as it passes through an electrical field. Collection efficiencies can be over 99.5% and unlike the mechanical devices, they are high for very small particulate sizes as well as for large particulate sizes.

The electrical resistivity of the ash particle is one of the major parameters which affects the design of electrostatic precipitators. If the layer of ash which builds up on the collecting plates of the precipitator has a high electrical resistance, a layer of insulation is effectively formed, thus reducing the collecting efficiency of the precipitator. On the other hand, low resistivity ashes rapidly lose their charge after collection and having thus dissipated the attractive force, they tend to re-entrain into the gas stream. Thus there is an optimum range of resistivity for efficient particulate collection. It has been determined that ash resistivity is influenced by the sulphur content of the fuel, the sodium content of the fuel and possibly by the moisture content of the fuel. The ash from high sulphur fuels (greater than 3% sulphur) can be collected easily by electrostatic precipitation, but it tends to re-entrain into the gas stream, and this makes good aerodynamic design of the precipitator very important if the ash is to be retained on the collecting plate. At normal flue gas temperatures of about 280°F, medium sulphur fuels (1.5% to 3% sulphur) generally have ash resistivities in the optimum range for efficient precipitation and, therefore, fewest problems in precipitator design. Low sulphur fuels (less than 1.5% sulphur) may exhibit high ash resistivities if sodium levels are low. This results in poor collection efficiency, if steps are not taken to counter the effect of the high resistivity. Alternative methods of combating high ash resistivity are as follows:

Hot Precipitators

The resistivity of most fly ashes varies with temperature and reaches a maximum at about 300°F, the temperature at which most conventional precipitators operate. At higher or lower temperatures than this, the resistivity reduces quite rapidly, so that in the 650°F to 700°F range, ash resistivities are at much lower levels and permit high efficiency collection. The disadvantages of this approach are that the flue gas volumes are much greater at these higher temperatures, requiring a much larger precipitator. Operating conditions at these high temperatures are also more severe, resulting in more difficult design problems. However, a hot precipitator is more versatile and can probably collect the ash from a variety of coals with acceptable efficiency.

Fuel and Gas Conditioning

As indicated previously, high ash resistivity can be attributed to lack of sulphur, sodium and/or moisture in the fuel. It has been demonstrated that, in some instances at least, the addition of sodium to the fuel in the form of sodium carbonate will reduce the resistivity of ash to acceptable levels and permit high efficiency ash collection. It has also been determined that some of the SO_2 produced from the sulphur in the fuel is converted to sulphur trioxide. Some of this sulphur trioxide condenses on the fly ash particle, in the presence of moisture in the flue gas, at about 300°F, to form a layer of sulphuric acid on the fly ash particle, which is conductive and thus lowers the resistivity of the particle. With low sulphur fuels, there is often insufficient sulphur trioxide available in the flue gas stream to maintain low ash resistivities. However, the addition of just a few parts per million of sulphur trioxide gas or sulphuric acid mist to the flue gas stream, is sufficient to reduce the resistivity of the ash particle to acceptable levels for efficient fly ash collection.

The difficulties of gas conditioning are associated with being able to distribute the very small quantities of sulphur trioxide throughout the flue gas stream, in such a manner that all the fly ash particles are treated and efficient collection is maintained throughout all sections of the precipitator. To our knowledge, there are very few precipitators using sulphur trioxide or sulphuric acid conditioning, which achieve collection

efficiencies which would be acceptable to Ontario Hydro.

Enlarged Cold Precipitators

The third alternative is to build a precipitator to operate at the conventional temperature of about 300^{o}F, but sufficiently large that the reduced efficiency caused by the insulating layer of high resistivity ash is overcome by the increased size, so that the desired collection efficiency is achieved. This of course results in increased capital cost and an increased operating cost due to increased power consumption and maintenance. For very high ash resistivities, cold precipitators tend to be larger and consequently more costly than a hot precipitator designed for the same service, although it may have fewer operating problems. Experience to date, with cold precipitators collecting high resistivity ashes, has been limited.

Coal Blending

In the case where both high and low sulphur fuels are available to a utility, a possible alternative is to blend the two fuels, thus reducing the maximum sulphur content of the fuel burned, but maintaining it within the range that is required for optimum ash precipitation. This can require a substantial capital outlay to provide blending equipment capable of producing a satisfactory fuel blend, in terms of consistency of sulphur content, and the operating costs associated with coal handling can increase significantly.

Meeting Provincial Air Quality Standards

Historically, all of Ontario Hydro's coal purchases have been medium sulphur Appalachian coal from the United States and some small quantities of similar Nova Scotian coal. Consequently, all of Ontario Hydro's existing electrostatic precipitators were designed for this easily collected ash. In the future, Ontario Hydro expects to supplement these Appalachian coal supplies with some low sulphur Western Canadian coal. It is expected that up to 4 million tons of this low sulphur coal will be imported into the East System by 1980. To take maximum advantage of the low sulphur content of this coal and yet ensure that our electrostatic precipitators will continue to operate with undiminished efficiency, it is intended to blend the Western Canadian coal with the Appalachian coal to produce a

blend with a sulphur content in the range of 1.5% sulphur to 1.75% sulphur. A recent test burn program at Nanticoke and Lambton to establish the viability of this approach, though not conclusive, has indicated that there are strong possibilities that this approach will work.

In the West System, the extension to the Thunder Bay Generating Station is being designed to burn lignite and a wide range of alternative coals. To be reasonably confident of maintaining high efficiency ash collection over a wide range of fuels of unknown ash resistivities, hot precipitators have been committed to these units.

The type of precipitators selected for future generating stations burning low sulphur coal will depend upon such factors as the ash resistivity of the design coals and their reliability of supply.

Hydro operates electrostatic precipitators at all its fossil fired generating stations. The precipitators on coal-fuelled units have design efficiencies of 99.5% or better, whereas those on oil-fuelled units have design efficiencies of 95%. All of these precipitators produce what is essentially a clear plume, a standard which is well within the Province's requirement of 20% opacity.

ii) Sulphur Dioxide

Sulphur dioxide is formed by the oxidation of sulphur in fuel during the combustion process. It thus becomes a constituent of the flue gases which are ultimately emitted to the atmosphere. There are five basic approaches to reducing the effects of sulphur dioxide emissions from generating stations on the environment.

Burn Low Sulphur Fuels

Ontario Hydro has used low sulphur fuels as a means of limiting ground level concentrations of sulphur dioxide under adverse meteorological conditions for a number of years. R.L. Hearn GS was converted to burn sulphur free natural gas, as well as coal, in the late 1960's and supplies of low sulphur coal were obtained and stored at Lambton, for use under adverse meteorological conditions. Studies of the feasibility of converting Lakeview to burn either natural gas or low sulphur oil were also made, though neither alternative was adopted, due to the inability to ensure an adequate supply of either fuel.

Currently, Ontario Hydro is preparing for the delivery of additional quantities of up to 4 million tons of low sulphur Western Canadian coal, which will reduce the average sulphur content of the coal burned from about 2.3% to about 1.7%. A contract has also been signed for the purchase of some Petrosar low sulphur residual oil, which will be burned at Lennox GS and Wesleyville GS. The Thunder Bay extension in the West System has been designed to burn low sulphur lignite and the proposed Atikokan GS is expected to burn low sulphur Western Canadian coal. It is also planned to convert J.C. Keith GS to burn low sulphur fuel.

Tall Stacks

Tall stacks improve the dispersion of the flue gases into the atmosphere, significantly reducing the concentrations of pollutants at ground level. Hydro's commitment to the principle of tall stacks began in the late 1950's, with the construction of the 500 ft. stacks at Lakeview. All generating stations built subsequent to Lakeview have stacks exceeding 500 ft. in height.

Load Reduction

Sulphur dioxide emissions can be reduced by lowering the load on a given generating station, if adverse meteorological conditions within its vicinity prevent it from meeting the provincial standards. The loss in generation would have to be made up from other generating stations, operating under less restrictive weather conditions. This technique requires accurate forecasts of adverse meteorological conditions, so that arrangements can be made to transfer load.

Fuel Desulphurization

Many processes, designed to reduce the sulphur content in fuels, are presently being developed in various parts of the world. These range from oil desulphurization by hydrogenation to coal gasification, liquefaction, and solvent refining. It appears that existing processes for fuel oil desulphurization and coal gasification are too expensive to make them realistic alternatives to other methods of sulphur dioxide control. Future processes, currently under development, are probably about ten years from commitment for commercial application. Ontario Hydro is monitoring the development of these processes and is prepared to actively investigate any which appear to offer

significant environmental advantages at acceptable cost.

Flue Gas Desulphurization

Considerable effort by governments, utilities and equipment suppliers, has been devoted to the development of flue gas desulphurization processes for the purpose of reducing the emissions of sulphur dioxide from fossil-fuelled generating stations. However, at this time, flue gas desulphurization has not been developed to the level where full scale systems could be committed, with acceptable risk to new or existing generating stations, for the purpose of reliably meeting air quality criteria. It seems unlikely that any flue gas desulphurization systems will achieve this level of development until the early 1980's at the earliest. Several systems are now in the process of being demonstrated at a large scale, or have reached the stage of development where a large scale demonstration project might be the appropriate next step. Over seven years after the first full-scale demonstration flue gas desulphurization system was installed on a utility boiler in 1968, there are now only approximately 22 demonstration systems installed in North America, many of them small by utility standards. The installed scrubbing capacity is approximately 3,800 MW out of a potential for scrubber application well in excess of 150,000 MW; many of these scrubbers operate only intermittently.

Most flue gas desulphurization processes involve scrubbing or washing of the flue gas. Because of the large volumes of flue gas which must be handled, the equipment is very bulky and expensive. Generally, processes are categorized as "recovery" or "non-recovery". Recovery processes recover the sulphur from the flue gas in the form of some useful by-product, such as concentrated sulphuric acid or elemental sulphur. Non-recovery processes discard large quantities of waste material containing the captured sulphur.

Non-Recovery Processes

The non-recovery processes have accumulated more operating experience, at least on coal-fuelled boilers. The principal processes involve lime and limestone scrubbing. In these processes the SO_2 is captured in a recirculated aqueous slurry. Slurry bled from the system is either disposed of directly in a pond or is dewatered to a mud-like sludge,

chemically stablilized by the addition of fly ash and other additives, and disposed of as landfill.

Initially these processes appeared to be the simplest and least expensive and received a large share of the interest and there were no by-products which required marketing. Several suppliers including Combustion Engineering, Babcock-Wilcox and Chemico, have studied these processes and built prototypes. TVA selected limestone scrubbing for full-scale demonstration at its Widow's Creek Plant. Ontario Hydro's Research Division conducted extensive pilot scale studies of the process. Because of this interest, lime/limestone scrubbing was expected to be the first process to achieve successful development.

The major problems which have been encountered with lime and limestone scrubbing are plugging due to build-ups of sludge and scale in the absorber and entrainment separator, erosion and corrosion due to the recirculating slurry, and handling and disposal of the large quantities of waste sludge. As experience with these systems and their problems has grown, their complexity and cost have increased substantially. In addition, dissatisfaction with the magnitude of the waste problem has been increasing. The Ontario Ministry of the Environment has indicated to Ontario Hydro that it does not consider non-recovery processes desirable, because of the waste disposal required.

Development progress has been slow, but recently, improved reliability has been reported by some lime/limestone scrubbing installations.

The Chemico/Mitsui carbide lime scrubbing system in Japan is reported to have operated reliably since its start-up in March 1972. Carbide lime is a by-product of the manufacture of acetylene. However, the process is operated "open-loop" which minimizes plugging but releases large quantities of dissolved solids to surface waters. Operating in this manner would generally not be acceptable in Ontario.

The Combustion Engineering carbide lime scrubbing system at Louisville Gas and Electric's Paddy's Run Station has also reported high availability. Sludge leaves the plant at 60-65% water content and is stabilized by mixing it with dry fly ash on an approximately 1:1 dry weight basis at the disposal site. L.G. & E. expect to receive $1.8M from the US Environmental Protection Agency for further studies of the process including studies on the aging and

leaching properties of the waste, on which there is presently very little information.

A Research-Cottrell limestone scrubbing system installed on a 115 MW boiler at Arizona Public Service Company's Cholla Station recently completed 12 months of operation. However, this station burns coal averaging only 0.5% sulphur content and Research-Cottrell have recognized that the scrubber used would not be suitable in its present form for use with higher sulphur contents. Furthermore, the Cholla scrubber system does not operate "closed loop". There is no sludge treatment; slurry is ponded directly and no pond water is recycled to the system.

Other installations have been less successful. Certainly some progress is evident. Waste disposal in particular still needs considerable development effort.

The double-alkali processes were devised in order to avoid the plugging problems of the lime and limestone slurry scrubbing systems. The flue gas is scrubbed with a clear solution of a highly soluble alkali, such as sodium or ammonia, which is regenerated outside of the scrubber with lime or limestone to produce a waste sludge similar to that from the lime/limestone systems. It is doubtful that the double-alkali processes offer any overall advantage over the lime/limestone processes.

There are some flue gas desulphurization processes which might be considered recovery or non-recovery, depending on the circumstances. Examples would be those processes capable of producing high quality gypsum (calcium sulphate) such as the Chiyoda, Hitachi, and Lurgi Sulfacid processes. Gypsum is used in the manufacture of some building materials such as lathing, sheathing and wallboard. In Ontario, gypsum is available naturally in large quantities at a high purity and low cost. However, in Japan it is not, and by-product gypsum from flue gas desulphurization plants is reportedly used in the manufacture of building materials. Investigations by Ontario Hydro to date have come to the conclusion that, for the present, such processes must be considered to be non-recovery processes, because of the lack of a similar market for by-product gypsum.

Recovery Processes

The variety of recovery processes under development is more extensive. Generally, the recovery processes are more expensive, and many require significant quantities of power and fuel, including natural gas, and involve handling hydrogen sulphide. They conserve some other resources and avoid the large quantities of waste associated with the recovery processes, but they require the marketing of a by-product. This is of critical importance, since the viability of the process may depend on the reliability of the market for the by-product.

Under some circumstances elemental sulphur may actually be considered to be a waste product. It is however, a relatively compact and trouble-free one; thus despite the fact that most sulphur is eventually consumed as sulphuric acid, and would be more costly to produce than acid, it might be the preferred product under uncertain market conditions because it is more easily handled, stored, and transported than acid.

The Chemico-Basic Magnesium Oxide Process is a regenerative process (the absorbent is regenerated for recycle to the absorber), which could theoretically be adopted to produce either elemental sulphur or concentrated sulphuric acid. The first prototype was installed at Boston Edison's oil-fuelled Mystic 6. During the two year demonstration project which ended in June 1974, the longest continuous run was only seven days. Boston Edison state that they would have "a high level of confidence" in building an improved future system, but so far have not committed any further scrubbers to their system. The first coal-fuelled application of the process was started-up in September, 1973 and is experiencing similar problems.

The Wellman-Lord Process can also produce either elemental sulphur or sulphuric acid. The process is reported to have operated reliably on oil-fuelled boilers and other applications. The first application to a coal-fuelled boiler is scheduled to start-up in early 1976 at Northern Indiana Public Service Company's Mitchell station. Development effort is presently directed at minimizing the costly and environmentally difficult 8-10% purge of sodium sulphate which is not regenerated in the process as currently offered.

In the Monsanto Cat-Ox Process sulphur dioxide is catalytically oxidized to sulphur trioxide which is condensed to 78% sulphuric acid. The 100 MW prototype system started-up in September, 1972 on the Illinois Power Company's coal-fuelled Wood River Unit 4 and has since operated less than 700 hours. The system is presently shut down indefinitely.

Ammonia scrubbing has been studied by both Tennessee Valley Authority and Ontario Hydro as a back-up to limestone scrubbing. The equipment involved in the absorption step appears to be relatively trouble-free but a major problem has been the emission of a persistent "blue fume" of very fine ammonium salt particulate. Recently however, some progress has been made on the fume problem. Several approaches to recovery are being investigated for combination with the absorption step. TVA has been pilot-testing one process, and an alternative, the IFP Process, is now being tested on a 35 MW utility boiler in France.

Cost Estimates

The estimated cost of flue gas desulphurization can vary considerably, depending among other things, on the process, unit and station size, capacity factor, sulphur content of fuel, market conditions for by-products, and whether the application is a new station or retrofit. As an indication, the Tennessee Valley Authority's November 1974 estimate covering several processes is in the range of approximately \$40 - \$60/kW for capital for a new 2,000 MW station and total cost estimates are in the range of approximately 3-4 mills/kWhr (capital and operating costs); a later statement by the National Electric Reliability Council quotes \$65-100 kW and possibly higher capital costs and operating costs of 2-5 mills/kWhr. In Ontario Hydro's opinion, the higher figures in these ranges are likely to apply.

Meeting Provincial Air Quality Standards

By maintaining its existing clean fuel supplies and making use of low sulphur Western Canadian coal, and some low sulphur residual oil, Ontario Hydro can continue to meet the Provincial Air Quality Regulations.

iii) Oxides of Nitrogen

Oxides of nitrogen are formed in all high temperature combustion processes, which use air as the oxidant. Atmospheric nitrogen and oxygen combine at high

temperatures to form nitric oxide, some of which is further oxidized to nitrogen dioxide in the flue gas stream, so that a mixture of these two oxides of nitrogen is emitted, along with the other flue gases, to the atmosphere. Nitrogen in the fuel may also combine with oxygen during the combustion process to add to the oxides of nitrogen present in the flue gas.

It has been determined that, though it is not possible to prevent the formation of oxides of nitrogen entirely during the combustion process, the rate of formation is dependent on the flame temperature, the amount of excess oxygen available, and to some extent, on the rate at which the air and fuel mix in the combustion zone. Boiler manufacturers have developed a number of modifications to their designs, based on these principles, which help to reduce the level of emissions of nitrogen oxides to the atmosphere. These modifications have in general been most successful with gas-fuelled units, moderately successful with oil-fuelled units, and have had limited success on coal-fuelled units.

They are:

Flue Gas Recirculation

Some of the flue gases are recirculated back into the combustion zone in the boiler, thus increasing the amount of inert gas in the combustion zone and consequently reducing the temperature of the flame.

Overfire Air

Some of the air required for complete combustion of the fuel is excluded from the combustion zone in the boiler and admitted at a level above the combustion zone. Thus, incomplete combustion occurs in the combustion zone, in an atmosphere which has little oxygen available for combination with atmospheric nitrogen. Complete combustion of the fuel then takes place in the region of the overfire air entry, but at reduced temperature, so that nitrogen oxide formation is reduced.

Reduction of Excess Air

Control of the quantity of air admitted to the boiler to be just sufficient for complete combustion of the fuel, reduces the amount of oxygen which is available to combine with nitrogen, and thus limits the

formation of nitrogen oxides. Typical values of excess air required for complete combustion are 7% for gas-fuelled units, 3% to 5% for oil-fuelled units and 18% to 25% for coal-fuelled units.

Burner Modification

Burners are modified to reduce the rate of mixing of fuel and air, slowing the combustion process, reducing flame temperature and thus, reducing nitrogen oxide formation.

Meeting Provincial Air Quality Regulations

Provincial regulations currently limit the point of impingement concentration of oxides of nitrogen to 500 micrograms/cubic metre, averaged over half an hour. Hydro currently meets this limit with no difficulty and it is, therefore, difficult to justify large capital investments and equipment outages in attempts to reduce nitrogen oxide emissions, which presently fall well within provincial requirements. Some intermittent brown plume problems may however require corrective action. Hydro has done extensive measurement and monitoring of its nitrogen oxide emissions in the past and will continue to do so in the future. Discussions have taken place with boiler manufacturers to explore means of supplying boilers designed to minimize the nitrogen oxide production.

iv) Particulate Sulphate

It has recently been recognized that particulate sulphate may be a pollutant and may be a contributing cause of respiratory problems. At this point in time, little is known about the formation of particulate sulphate or its effects on the population.

With specific reference to generating stations, it is known that sulphur trioxide in the flue gas can condense on fly ash particles, to form sulphate on the outer surface of these particles. Some of these fly ash particles, approximately 0.5% of those entering the precipitator on a coal-fuelled unit, are emitted to the atmosphere. Sulphur dioxide in the atmosphere, some of which is emitted by generating stations, is also known to react with other components of the atmosphere to form particulate sulphate and sulphite. At this point in time, however, it is not known how the rate of particulate sulphate formation is affected by the concentration of sulphur dioxide in the atmosphere.

There also seems to be a large gap in knowledge of the effects of particulate sulphates.

Research

Ontario Hydro is a member of the Electric Power Research Institute and has representation on a steering committee which directs the research of the institute into sulphate particulates. Hydro has also set up a series of sulphate monitoring stations of its own and has also measured the oxidation rates of sulphur dioxide to sulphur trioxide in some stack plumes. This data will be used as the basis of work to determine the formation mechanism of particulate sulphates.

It is Ontario Hydro's belief that this basic research into the formation mechanism and effects of particulate sulphates must be carried to a point where meaningful conclusions can be made, before any policy for the control of particulate sulphates can be formulated, with any hope of success.

(b) Water

Section 6.1 C(d) discusses the cooling problems at thermal generating stations in some detail.

Ontario Hydro presently employs once-through cooling at all thermal generating stations, using the natural cooling resource provided by the Great Lakes as a sink from which the heat is transferred to the atmosphere. Once-through cooling is the lowest cost method of condensing steam so its use produces substantial savings to the province in the form of lower cost electricity. Ontario Hydro recognizes that as with all renewable natural resources, excessive use may lead to harm and loss of this resource. The main concern expressed by the regulatory agencies relates to the thermal modification of the near shore areas where fish spawning and migration may occur. Ontario Hydro has been conducting on-site studies since 1968 at thermal generating stations to determine the influences of discharges of heat at the shoreline on the various aquatic organisms constituting the near shore ecosystem. At one station, Nanticoke, there is a cooperative program between the Ministries of the Environment and Natural Resources, Ontario Hydro and two other industries located in the area. All these studies to date indicate that the thermal discharge may cause shifts in the composition and populations of organisms in the area close to the discharge point. These shifts, in Ontario Hydro's opinion, do not appear to be large enough to constitute other than a very localized influence on the

near shore ecosystem. In addition, this influence if it occurs, may not necessarily be construed as an adverse influence.

Shoreline discharges are more likely to modify the natural thermal regime in the near-shore areas than a similar discharge of heat located some distance offshore. However, such offshore discharges may have a greater effect than shoreline discharges because of increased damage to the organisms entrained in the warmed cooling water flow.

Localized fluctuations in shoreline temperatures due to thermal discharges are very small relative to the large, frequent and often violent fluctuations occurring in the Great Lakes due to natural causes such as seiche action and storms. These variations are shown in Diagram C of Section 6.1. The aquatic life characteristics of the exposed shoreline of the Great Lakes reflect these natural, variable conditions.

Extensive and detailed studies, now in progress, include comparisons of the environmental effects of onshore and offshore discharges. Results of these studies will be of value in deciding on the preferred location of new thermal stations and the thermal discharges from them. Offshore discharges have been investigated but their higher cost is difficult to justify at present in the absence of any indication of significant or irreversible effects from onshore discharges.

To dispose of the heated effluent several thousand feet offshore cannot be justified scientifically or on a cost basis with present knowledge of the impact of onshore thermal discharges.

Electrical generating stations discharge relatively small amounts of chemicals. As part of the project approval process for new generating stations, Ontario Hydro provides details of proposed pollution control equipment, expected discharge concentrations of chemicals and in some cases the amounts. Permits and approvals are provided based on the levels of emissions required for the maintenance of acceptable water quality as laid down by the Ministry of the Environment in the Guidelines and Criteria for Water Quality Management.

Extensive data are being accumulated on the majority of chemicals being discharged based on toxicological, chemical and dispersion studies. In operating plants, Ontario Hydro is continuing to upgrade those systems which release some chemicals to the water body. The trend is to progressively reduce the levels of discharged chemicals

and in some cases attempts are being made to completely eliminate them.

(c) Land

The sources and quantities of solid wastes from both fossil-fuelled and nuclear-fuelled stations are identified in the Environmental Assessment for each project. Descriptions of the various sources and quantities of wastes with the proposed methods of disposal are reviewed with the appropriate regulatory agencies prior to approval of a new generating station. At this stage, there has to be approval in principle for the disposal methods. Subsequently, approval has to be obtained from the Ministry of the Environment for the collection, transportation and disposal of individual types of wastes during construction and operating of a generating station.

The most important solid waste from an operating fossil-fuelled generating station are fly and bottom ash. Wastes common to both fossil-fuelled and nuclear-fuelled generating stations include screenhouse materials consisting mostly of floating debris, fish and weeds; water treatment plant sludge; and sewage sludge and oil at construction sites. Other important wastes are from construction materials and from the construction camp, if present. Ontario Hydro disposes of solid wastes in accordance with the procedures set down by the Regulatory Agencies.

Fly ash, the solid waste produced in greatest volume from coal-burning stations, is presently being satisfactorily disposed of in land fill sites. Some fly ash is being used in light weight aggregate.

F. Conventional Hydraulic and Pumped Storage Generating Stations

The environmental effects of a hydraulic project depend largely on its location and size. All such effects are not necessarily adverse and in some cases the projects may be designed to produce some environmental benefits such as provision of an area for water-based recreational activities.

Changes in water quality may occur both upstream and downstream of a project. In the flooded areas there is generally a deterioration in water quality during the early years of operation. Long term water quality changes are associated with the degree of initial clearing of vegetation, the type of operation of the storage facilities and such factors as the stability of the reservoir shorelines. Downstream of the facility, the water may have a lower silt load and the

fluctuating flow will influence water levels and erosion and deposition patterns. Temperatures downstream will be influenced by the mode of operation of the facility.

Influences on the aquatic environment are usually site specific and are associated with the changes in water temperatures, nutrient levels and water levels and flows. Generally, populations and species distribution of native fish species are found to change both upstream and downstream of the facility. Little success has been recorded in transporting fish over hydroelectric dams and through storage reservoirs. Terrestrial fauna are adversely influenced by loss of habitat due to reservoir flooding, road construction and transmission line right-of-way construction.

Most of Ontario's remaining undeveloped hydraulic resources are located in relatively remote areas of the Province. Apart from the immediate effects on land utilization such as headpond flooding, roads, airports and other forms of communication, long term impacts on the region may arise due to its increased accessibility as a consequence of development of hydraulic generating stations.

Ontario Hydro's existing hydraulic generating stations were constructed before the need was perceived for a detailed environmental analysis. Future generating stations will require a thorough environmental investigation.

In an aboveground pumped storage facility where water is taken from an existing water body to a reservoir at a higher level, the main terrestrial influences will be in the loss of land and natural habitat. Entrained aquatic organisms, particularly fish, will generally experience heavy mortality due to mechanical damage during pumping and to changes in pressure. In the upper reservoir, the large changes in water levels would tend to provide an unfavourable environment for maintenance of a stable aquatic community, particularly if erosion of the reservoir banks was not controlled. Changes in water level would discourage development of water-orientated recreational activities.

Where water is pumped from an underground storage reservoir to an upper lateral water body, the main impact would be during the construction phase where large volumes of rock must be removed from the site. During operation, entrained organisms would be killed by mechanical and pressure stresses. This concern would also present a possible water quality problem if large quantities of organisms are entrained. If the upper reservoir was a discrete water body, dedicated to pumped storage, these entrainment concerns would not exist. Some heat will be added to the pumped water by friction and by contact with subterranean rock. The overall impact of pump storage

facilities could, therefore, vary from low to high depending on the type of reservoirs used.

G. Aesthetics

At new stations an attempt is made to make such aspects as layout, profile and surroundings as pleasing to the viewer as is reasonable. Aspects of a fossil-fuelled generating station that may be visually displeasing include the stack, any visible plume, and fuel storage piles. The purpose of the stack is to discharge the gaseous emissions at a sufficient height to allow effective dispersion. The improved appearance of a shorter stack could not be justified if increased ground level concentrations of pollutants result. In winter, condensation of the water vapour produces a visible white plume. Water vapour is a product of combustion of fossil fuels containing hydrogen (which combine with oxygen) and moisture which is vaporized and cannot be avoided. Other stack emissions do not normally contribute to a visible plume.

A CANDU nuclear station generally does not have a stack, and has ventilation ducts instead. It does not emit visible pollutants which may be aesthetically displeasing.

Noise levels from an operating generating station do not normally exceed background levels at the site boundary. Occasionally, steam release valves may create a noise. The use of mufflers reduces noise from such valves to a low level. Some measures to reduce the noise levels for the protection of operating staff may contribute to a reduction in noise levels at the site boundary.

H. Summary of the Environmental and Safety Aspects of Electric Generating Stations

The issues involved in environmental and safety effects arising from the production of electricity are complex and their evaluation requires detailed and very technical investigation and analysis. This section attempts to summarize the results of the pertinent factors involved in the analyses in a form that can be understood and assessed by the public.

(a) Accidents and Injury

In comparing the possible risk to the public from accident in electricity production by fossil and nuclear means, it is necessary to include all related areas which may result in public risks. There has been a tendency to concentrate public concern on some aspects while neglecting other real risk areas. For example, there has been much discussion about the risks to the public from operating nuclear

stations while ignoring the mining, transportation, and materials handling aspects associated with both fossil and nuclear energy production.

Intensive investigation of nuclear safety has been undertaken from the beginning of nuclear power plant development in Canada and the rest of the world. Nuclear stations are designed and built to a very high standard and include many overlapping safety and containment systems and periodic inspection programs which ensure no deterioration with time of the high level of integrity of the components and safety systems. Over 100 nuclear power stations are now operating in the world, and hundreds of years of operating experience of these nuclear power stations have been accumulated without a single fatality to the public or to the operating staff due to nuclear causes.

A measure of the risk to the public from the operation of nuclear stations can be assessed by reference the data shown in Section I below. These data are taken from Dr. Rasmunsen's report (Reference 6.4(23)) of a very thorough assessment of the accident risks in the United States from nuclear power stations. They show the relative risk of accidental death from nuclear plants compared to other man-made and natural events. The public risk from nuclear accidents is much less than that from many other commonly accepted hazards in the United States. Although Hydro's CANDU nuclear stations differ somewhat from those in the United States, these CANDU stations have outstanding safety features, and the risk from nuclear accidents in Ontario would be much less than one per cent of other hazards accepted by the public.

The more important accident and injury risks to the public from electricity production arise in the mining of coal and/or uranium to fuel the stations and in the handling and transportation of the fuel and waste products. Statistics from References 6.4(24), 6.4(25), and 6.4(26) indicate that underground mining and transportation of coal for a fossil-steam station results in a risk of public accidents many times greater than operating the fossil generating station and at least ten times that compared to the mining and transportation of natural uranium fuel for a similar size nuclear station. The actual operation of either nuclear or fossil stations contributes an insignificant public risk. In considering all the activities involved in providing the electrical energy (mining, transportation, construction and operation of generating stations) there are substantially higher public risks in coal-fuelled fossil-steam generation compared to nuclear generation. Oil-fired fossil-steam stations appear to present about the same public risk due to accidents as do nuclear stations.

(b) Environmental and Health Hazards of Effluents from Generating Stations

The effluents from generating stations during operation may result in adverse environmental or health effects. It is difficult to undertake a rigorous comparison of the effects of the various effluents from each type of station (fossil and nuclear) because the effluents differ in nature and type and because they are generally not distinguishable from background levels.

Liquid Effluents

Both fossil-steam and nuclear generating stations discharge waste heat to the environment. The nuclear stations discharge about 80 per cent more heat to the condenser cooling water than do fossil-steam stations and in this regard are less favourable. However, in Ontario this waste heat has been dissipated by using the very substantial cooling capability of the Great Lakes and rivers adjacent to the load centres. Careful monitoring of the effects of warm-water discharge to the Great Lakes over a number of years has not revealed significant adverse environmental effects.

Liquid effluents from a nuclear station may contain minute quantities of radio isotopes, but any liquid effluent is carefully monitored and will be below drinking-water tolerance before dilution in the receiving body. Limits recognize two pathways to man: drinking water and fish consumption. Even if fish, which live all their lives in the plant effluent, are eaten every day by an individual and drinking water is taken undiluted from the outfall channel, the allowed dose to the individual would not exceed the one per cent target.

Gaseous Effluents

Gaseous effluents from fossil-steam stations consist of the products of combustion (CO_2 and H_2O) with a variety of compounds such as oxides of nitrogen and a large number of impurities, mainly sulphur, plus trace elements which were in the fuel, and including radioactive components. The physiological effects from inhalation of a mixture of SO_2 and particulates are unknown in the very dilute concentration allowed to exist at ground level, but are considered to be acceptably small based on laboratory tests on animals at higher concentrations (see Reference 6.4(27)). However, the regulated levels and ambient levels for SO_2 plus particulate are not far below those at which medically perceivable effects to humans and damage to sensitive vegetation are found.

The flue gas from a coal-fuelled fossil-steam generating station contains minute quantities of uranium and thorium and associated long-lived emitters of alpha radiation. It

is not possible to detect any variation in ambient background levels of radioactivity due to these releases. Adverse effects on health of these releases of radioactive materials or other trace elements in the flue gas from coal stations is therefore unknown but believed to be small compared to other sources.

In nuclear stations there is no combustion and no gaseous discharge like that from a fossil station. The portion of the station containing the nuclear systems is on closed cycle ventilation with only minor discharge to the atmosphere. Ventilation flow through the portion of the station that is accessible to persons during operation is discharged from ventilation ducts. This ventilation may contain minute quantities of radioactive material which come from laboratories or nuclear processes. The flow is continuously monitored for its radioactive content by very sensitive instruments. In the event that activity is detected, the ventilation flow can be shut off or automatically directed through filters and activated charcoal to remove radioactive particles and active gaseous chemicals. At Pickering this arrangement limits the releases to less than one per cent of that allowed by the Atomic Energy Control Board. The effects of these releases of radioactive isotopes on the surrounding population are believed to be less than the effects of many other random sources of radiation such as: mining and processing of gypsum and its fabrication into gyproc lath used in housing; mining of phosphate containing uranium and radium 226 and its subsequent use in fertilizers; and mining and use of lead containing trace radioactive containments. Contributions to and variations in the public individual radiation dose levels are affected more by the above industries and the type of materials of construction of the house one lives in (e.g., masonry as compared to wood), the elevation of the office building in which one works, and the frequency of air travel, than by releases of radioactivity from nuclear generating stations. Even the glaze on earthenware commonly used in restaurants is estimated to contribute more to public dose than the nuclear power industry.

Solid Wastes

Solid waste products of fossil-fuel combustion (fly and bottom ash) are typically disposed of in land-fill sites or can be incorporated into a light-weight aggregate product. Either of these disposal methods may be regarded as beneficial provided that no further adverse environmental influences occur during processing or disposal. This ash contains most of the trace elements originally in the coal, including radioactive isotopes and heavy elements.

Solid wastes from nuclear stations are much smaller in volume compared to those from a fossil station on a basis

of equal energy output, but they may be radioactive. These low and intermediate radioactive wastes are placed in engineered reinforced concrete trenches which are provided with perimeter activity monitors and monitored under drainage systems.

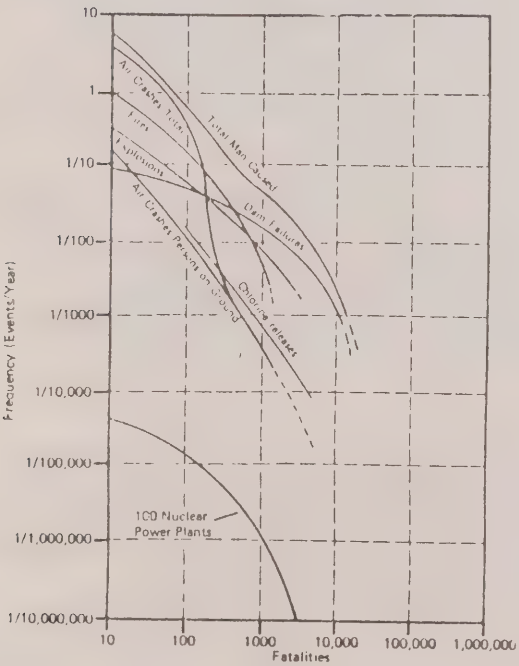
Solid wastes from fossil and nuclear stations are not considered to be a significant environmental or health hazard. However, the nuclear wastes are placed under more strict management control and are isolated from the environment.

Summary

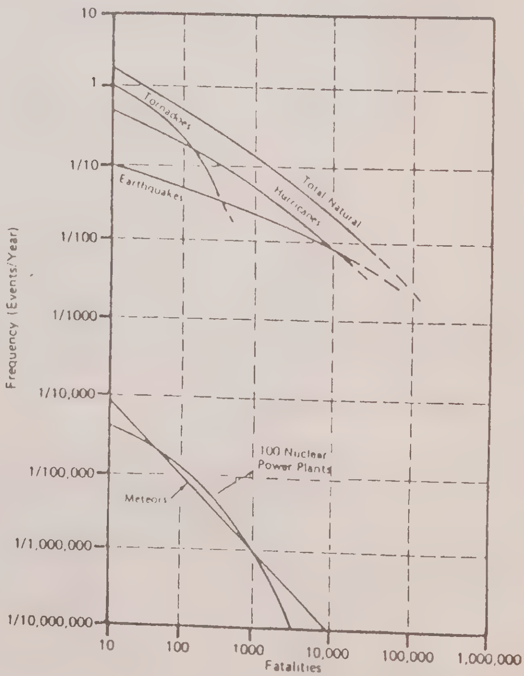
Although there is need for improved data and assessment of the effects of trace elements, it is concluded that generation of electricity by nuclear means presents fewer risks to the public due to accidents and substantially higher ambient air quality than generation of the same amount of electricity by coal-fuelled fossil-steam plants.

I. Frequency and Risk of Fatalities Due to Various Causes

(a) Frequency of Fatalities Due to Man-Caused and Natural Events



Frequency of Fatalities due to Man-Caused Events



Frequency of Fatalities due to Natural Causes

Notes:

The above information is extracted from Refence 6.4(23) and applies to the USA.

Fatalities due to auto accidents are not shown because data is not available. Auto accidents cause about 50,000 fatalities per year.

An example of the numerical meaning of the above graphs can be seen by selecting a vertical consequence line and reading the likelihood that various types of accidents would cause that consequence.

For instance, the 100 fatality line indicates the probability that a single accident would occur and result in 100 fatalities in one year. This line indicates that the probability of this happening with 100 nuclear stations is about one chance in 100,000 per year, i.e., one chance in about 100,000 years. The probability of this happening with chlorine releases is 1,000 times more likely, or about one in 100; with fires is about 10,000 times more likely or about one in 10; with air crashes about 50,000 times more likely or about one in 2 years.

(b) Average Risk of Fatality by Various Causes in Terms of an Individual's Chance Per Year

Accident Type	Total Number	Individual Chance per Year
Motor Vehicle	55,791	1 in 4,000
Falls	17,827	1 in 10,000
Fires and Hot Substances	7,451	1 in 25,000
Drowning	6,181	1 in 30,000
Firearms	2,309	1 in 100,000
Air Travel	1,778	1 in 100,000
Falling Objects	1,271	1 in 160,000
Electrocution	1,148	1 in 160,000
Lightning	160	1 in 2,000,000
Tornadoes	91	1 in 2,500,000
Hurricanes	93	1 in 2,500,000
All Accidents	111,992	1 in 1,600
Nuclear Reactor Accidents (100 plants)	-	1 in 5,000,000,000

Notes:

The above information is extracted from Reference 6.4(23) and applies to the USA for the year 1969, except for the 100 nuclear plants expected to be in operation by 1980.

J. References

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6.5 THERMAL GENERATING STATION SITES

Contents

Figures (Bound in Volume 2)

6.5 Thermal Generating Station Sites

A. Summary

The primary objective of the site selection process is to ensure that suitable sites are available when needed. These sites must be technically feasible, desirable from the cost viewpoint and socially and environmentally acceptable for future generating stations. The selection is done by gradual elimination of the less suitable sites. The selection criteria include a wide range of technical, legal, societal, environmental and cost constraints, and general and specific requirements. The activities involving representatives of various levels of government and the general public represent one of the major parts of the selection process.

Ontario Hydro's position is that it should acquire a number of generating sites at feasible locations throughout Ontario, and, as far as practicable, stage the development of these sites in an orderly manner. It is considered that the development of a smaller number of sites, accommodating for the most part large generating capacities is preferable to and less costly than a proliferation throughout the Province of a large number of sites with smaller capacities. It is important to note, however, that the orientation toward the large generating centres does not preclude development of smaller generating facilities in situations where they are technically, environmentally and from the cost viewpoint more acceptable than large generating facilities.

Concentrations of generating facilities located on one site are usually referred to as energy centres. Ontario Hydro proposes to use an energy centre capacity of about 12,000 MW as a basis for site selection. If required, energy centre sites may also provide for the appropriate location of other facilities associated with power production. The energy centre concept offers the potential of efficiency to the system, reduced cost in station construction and operation, and more efficient land use at the generating station sites.

It is preferable, from the natural environment viewpoint, that sites with a potential for development beyond the initially installed generating capacity be developed in separate stages. This would allow for assessment of the effects on the environment of the facilities already operating on the site before proceeding with the next stage of development. On the other hand there are other considerations supporting the uninterrupted development of sites such as costs and community impact.

In addition to discussing the factors affecting the acquisition of new generating station sites, this section outlines the generating installations in-service and under construction at sites already owned, and the capability of the sites for further development.

B. Main Siting Criteria

The criteria constituting a siting requirement can be separated into several main categories. Each category covers a particular aspect of the siting requirement, but it is difficult to establish definite dividing lines between the categories. In fact, most criteria can be identified as being in two or more categories. The division of siting criteria into technical, legal, societal and socio-economic, environmental, and cost criteria categories, appears to be the most logical.

(a) Technical Criteria

These include criteria dealing with the existing conditions and future technical requirements such as those for foundations, cooling, seismic phenomena, access to the site and transmission egress.

(b) Legal Criteria

For any site, these may encompass the public, private, municipal, provincial, and federal interests, including the use of Federal and Provincial lands and Indian reserves. They also encompass international and interprovincial relations.

(c) Societal Criteria

These include planning implications of the development, the role of all three levels of government, and the possible effects on residents in the immediate vicinity of the site. Socio-economic criteria deal with economic effects arising from the development in an existing community, and with changes expected in the fabric of local society.

(d) Environmental Criteria

These include the long-term effects of station construction and operation on land, air, and water on and around the site. It is a fact that no human activity can be undertaken without some effect on the environment.

(e) Cost Criteria

These include a comparison of the development costs associated with alternative sites. The key issue in this comparison is the difference in cost between the alternative sites.

It is inevitable that for any major development, there are both adverse and beneficial effects under most of the preceding factors. It is also evident that tradeoffs must be made between these effects and these are subject to government and public review under the new Environmental Assessment Act.

The basic criteria to be considered in site selection are essentially the same for any size of generating facility, and for all locations of the site. However, the relative importance of the criteria may change from one location to another, and from one time to another.

C. Influence of Facility Size on Siting

A generating site may accommodate either a single or a multiple station development, and either a small or a large total generating capacity. Which of the alternatives will be chosen depends on the regional and overall system requirements and cost and social factors, as well as the suitability of the site.

The total generating capacity developed at a site and the size of station components can vary considerably from one case to another. Cost comparisons usually govern the minimum size of a generating facility. On the other hand, for reasons of system reliability, the current policy is, where possible, to limit the maximum generating capacity at the site to less than the amount of the total system generation contingency reserve. Technical, cost and environmental considerations may decrease this maximum amount of generation on any one site. For example, the currently considered maximum for a coal-fired facility with present pollution abatement equipment, and the most favourable siting conditions is about 4,500 MW.

Selection of unit sizes depends on a balanced judgement of a number of factors including costs, equipment reliability, manufacturers' capability, development problems, flexibility of operation, system capacity and reserve requirements, and transmission system capability. For Ontario Hydro's application, currently considered maximum size of fossil units is 750 MW. It is expected that the maximum size of nuclear

units in Ontario will be 850 MW in the 1980's, 1,250 MW by the 1990's and about 2,000 MW before the end of the century.

It is expected that the future development of generating facilities will generally be in the form of large stations each containing four or more units. Potential sites for smaller generating stations are more numerous than the sites for larger centres since the requirements for cooling water are lower. Sites for smaller generating facilities are smaller than energy centre sites, although the size does not decrease in a direct proportion to the amount of generation.

Typical layouts of waterfront generating stations using once-through cooling are shown in Figures 6.5-1 to 6.5-5. Alternative cooling systems such as cooling towers, cooling ponds and spray canals impose significant increases in the cost of power and also require additional acreage, some of which may be within the nuclear exclusion radius. Supplies of dependable make-up water and blow-down treatment limit the cooling capability of many sites. (See Section 6.1 C(d)). The utilization of some of the waste heat for beneficial purposes is unlikely to significantly reduce the need for extensive cooling systems.

D. Alternative Siting Locations

A thermal generating station could theoretically be sited in many differing locations. However, the technical, legal, societal, environmental and cost requirements discussed previously reduce the number of feasible sites.

The sites at or near the shores of large bodies of water such as major lakes and rivers are considered to be the most suitable locations for thermal generating stations. This is based on the availability of cooling water and on the need for shipment by water of large, heavy equipment components.

Ontario has many lakes and rivers, but most are small and do not meet the technical and/or environmental requirements for location of generating stations using once-through condenser cooling.

All existing operating fossil-fired and nuclear generating stations in Ontario, as well as those under construction, are located on the shores of the Great Lakes and their connecting rivers. Because of future increases in required generation, other site locations, such as inland, offshore, urban, and underground, will also be considered.

(a) Waterfront Sites on the Great Lakes System

These are the sites along the Great Lakes and their connecting rivers. From the technical viewpoint they are the best of all siting alternatives in Ontario because they can support large generating stations using once-through condenser cooling. It is important, however, to note that the once-through cooling concept will not necessarily be the only future cooling alternative, and that some other cooling method (cooling towers, natural and spray ponds), currently considered not competitive and unsuitable for Ontario conditions, might also be used.

Besides the excellent accessibility by land and water, and abundance of cooling water, the lower Great Lakes sites are also, in general, close to existing development and load centres. Hence they can use shorter transmission, and more readily draw upon available human and material resources. Great Lakes sites require less land space for nuclear stations since the 3,000 foot exclusion zone around the reactors is partially over the water. The main disadvantage is competition for land with other types of land use.

(b) Inland Sites

Inland sites are those located more than, say, 5 miles from the shores of the Great Lakes and their connecting rivers. They could be located away from densely populated areas and in areas which are less sensitive to development. Inland siting would free shoreline areas for other developments.

Inland sites may be more limited as to capacity. They will require more expensive and less efficient methods of condenser cooling, which have their own environmental and operational difficulties as compared to the once-through cooling. They are not accessible by water which may result in problems with transport of heavy equipment. Also, they may require up to twice the land area compared to nuclear plants located on lakefront sites, because less of the exclusion zone is over the water.

(c) Urban Sites

The early thermal generating stations built by Hydro (Keith, Hearn, Lakeview) were located in urban areas. Urban sites generally require fewer transmission facilities, are more accessible, and are close to material and human resources and amenities required by construction

and operating personnel and their families (housing, educational facilities). Future development in the field of urban siting will examine the potential for utilization of rejected heat in space heating, sewage treatment, etc.

The disadvantages of urban siting of generating facilities are mostly environmental. More people are affected in areas such as aesthetics, traffic, fuel delivery, waste disposal, and air and water quality. Competition for choice land with other types of development is another important factor. It is unlikely that nuclear generating stations will be considered for urban locations.

(d) Offshore Sites

The location of a generating facility offshore on a large body of water such as one of the Great Lakes offers an alternative to the land-based sites. The concept is not new and various schemes have been proposed including an artificial island, a completely submerged station, a rigid platform-mounted station, and a barge-mounted station protected by a breakwater. However, many problems still have to be resolved. Recently, the advanced plans for construction of floating nuclear facilities on the Atlantic Ocean off the coast of New Jersey have been shelved for an indeterminate time.

Although technically feasible, offshore siting appears to be very expensive and not justifiable in Ontario at this time. Reliability of such stations has not been demonstrated. Offshore siting may be more acceptable to the general public, and concurrent construction of the plant and site development might shorten the required lead time.

(e) Underground Sites

Underground siting of hydraulic generating station components has been practised since the turn of the century. Recently, because of the growing concern for environmental preservation, the underground siting of thermal generating stations, particularly nuclear stations, is being considered as a possible alternative to surface siting. Four small nuclear reactors, all in Europe, have been built underground, but technical feasibility of underground siting of large nuclear generating stations has not yet been demonstrated. Ontario Hydro has not carried out any detailed studies of this concept.

E. <u>Heavy Water Plant Siting</u>

Heavy water plants are licensed by the Atomic Energy Control Board which has established several constraints and requires that approvals be obtained for the site, the construction of the plant and the operation of the plant.

The application for site approval must show that there are no characteristics of the site or its surroundings which could significantly increase the risk posed by the plant to the health and safety of the public or of plant employees.

The main hazard in heavy water plants lies with the large quantities of hydrogen sulphide (H_2S) used in the chemical process. This gas is toxic even at low levels of concentration. Because of the presence of this gas, strict attention is given to controlling minor releases and preventing larger releases of H_2S. Section 6.3(D) discusses this matter in more detail.

Heavy water plants use large quantities of process steam and this can be most economically provided from a nuclear-fuelled generating station.

F. <u>Transmission Requirements</u>

The number of transmission circuits required to incorporate a generating station of a given size depends on security criteria and circuit capability which are discussed more fully in Section 7.0 and Appendix 7-A of this report. In addition, the choice of voltage for the transmission facilities and the type of line selected (one- or two-circuit) to incorporate the generation depend, not only on the size of the initial generating station, but also on its planned ultimate size and distance from major load centres.

Ontario Hydro's existing thermal generating stations are incorporated using 115 kV, 230 kV and 500 kV transmission lines. The use of the higher voltage transmission lines becomes more attractive as generating stations increase in size and as their locations become more remote from large load centres. It is expected that most large future stations will be incorporated using 500 kV lines.

It may be possible to incorporate small generating stations into existing grid systems with minor modificiations. The actual configuration of transmission facilities and the land area affected would depend on the amount of generation installed and the existing local transmission system.

Transmission for a Single Station (3,000 to 5,000 MW)

In order to meet the security criteria discussed in Sections 7.0 and 12.0, the incorporation of a single generating station of 3,000 to 5,000 MW capacity requires a minimum of three 1-circuit lines or two 2-circuit lines regardless of the maximum design capability of the circuits. However, depending on the distance to load centres, additional circuits may be required.

Transmission for an Energy Centre (Up to 12,000 MW)

The incorporation of an energy centre with capacity up to 12,000 MW will require about six 1-circuit 500 kV lines or three to four 2-circuit 500 kV lines which should be located on two separate rights of way at least 5 miles apart. It is desirable that the transmission lines diverge on the separate rights of way as soon as possible after leaving the station site. If this is not practicable, the length of the common right of way should not exceed 15 to 20 miles and fall-free spacing should be provided between the two groups of transmission lines. Both of these criteria are designed to reduce as much as practicable the probability of the loss of the output of an entire energy centre due to a catastrophe knocking out all transmission lines emanating from the centre.

G. Siting Procedures

Formerly, the siting of a generating station was largely an internal function of Ontario Hydro. Under the provisions of the Power Commission Act, Ontario Hydro was vested with power to acquire any land, lake and/or river for the production, transmission and distribution of electric power with the approval of the Ontario Government. The general public had little direct influence on location of the facilities for such purposes.

Within the last few years, in recognition of the fact that the siting of a generating station and the associated transmission is a significant aspect of land use which affects the environment, a siting procedure incorporating the information from various government agencies as well as from the general public has been used by the Corporation.

Ontario Hydro believes that the responsibility for the selection of sites for future generating stations is an integral part of the Corporation's function. In the future the acquisition of sites will fall under the regulations of the Environmental Assessment Act.

Experience to date indicates the site selection process, including public participation preceding site approval, requires 2 or more years for each site.

H. Existing Thermal Generating Station Sites

(a) Inventory of Installed and Planned Facilities Up to 1986 at Sites Already Owned by Ontario Hydro

EAST SYSTEM

Generating Station	No. of Units	First Power Dates	Installed Capacity (Nameplate Rating) kW
Fossil-Steam			
R.L. Hearn	4	1951-1953	400,000
	4	1959-1961	800,000
Total			1,200,000
J.C. Keith	4	1951-1953	264,000
Lakeview	8	1961-1968	2,400,000
Lambton	4	1969-1970	2,000,000
Nanticoke	8	1972-1977	4,000,000
Lennox	4	1975-1977	2,000,000
Wesleyville	4	1979-1981	2,000,000
Combustion Turbines			
R.L. Hearn	3	1967	22,500
Lakeview	3	1967	22,500
Lambton	3	1967	22,500
J.C. Keith	1	1967	7,500
Sarnia-Scott	4	1965-1966	62,640
Detweiler	4	1967	65,280
A.W. Manby	4	1965-1966	65,280
Pickering	6	1971-1973	45,000
Bruce	4	1974-1976	58,000
Nanticoke	3	1971	22,500
Nuclear-Steam			
Douglas Point	1*	1967	200,000
Pickering "A"	4	1971-1973	2,160,000
Pickering "B"	4	1981-1983	2,160,000
Bruce "A"	4	1976-1979	3,000,000

Nuclear Power Demonstrator	1*	1962	20,000
Bruce "B"	4	1983-1986	3,000,000
Darlington	4	1986-1987	3,400,000

* Not fully owned by Ontario Hydro

WEST SYSTEM

Generating Station	No. of Units	First Power Dates	Installed Capacity (Nameplate Rating) kW
Fossil-Steam			
Thunder Bay	1	1962	100,000
Thunder Bay Extension	2	1979-1980	300,000
Combustion Turbines			
Thunder Bay	2	1968	28,300

(b) Probable Maximum Capacity of Existing Sites in the Period Up to 1995

A judgement as to the "Probable Maximum Capacity" of a site is influenced by factors such as physical, environmental, regulatory, legal, technological, cost constraints and public acceptance. These factors change from location to location and from time to time.

The following estimate of the "Probable Maximum Capacity" is made against a background of currently acceptable conditions. The time span is assumed to be 1983-1995.

R.L. Hearn

The first four 100 MW units will have completed 30 years of service by 1983, however, their usefulness for peaking service or reserve is likely to continue beyond that date. In their present condition, these units can only burn natural gas.

The changing energy and economic climate may indicate the redevelopment of these generating units for the supply of district heating or for heat recovery from refuse, providing that such schemes become practical. Either use is likely to require greater fuel consumption than at present; and this may have to be in the form of coal rather than gas.

The last four 200 MW units will have completed 30 years service in 1991. These units are efficient, and are likely to be used for low capacity-factor generation and for peaking and standby service well after 1995. They can burn both natural gas and coal.

Depending on the availability of alternative sites and associated transmission rights of way, it may be necessary to partially redevelop the site with larger and more efficient turbine-generator units.

If natural gas and/or low (1/2%) sulphur (Western) coal is available for power generation, it may become possible to replace the existing four 100 MW units by two 500 MW units, and still meet current regulatory standards. This would require extensive modification to the present cooling water circuit.

J.C. Keith

The four coal-fired units at this station which have a combined capacity of 264 MW, will have completed 30 years service in 1983. The lifetime of these units will depend on the modifications they will require within the next few years to continue operating. The plant has a number of problems including those of foundation, emission control, and high cost.

It would appear that any redevelopment of the site would be directed toward the supply of district heating or heat recovery from refuse, if these systems become feasible and desirable. Both of these processes may require a considerable increase in the amount of fossil fuel consumed by the plant.

Lakeview

With its present eight 300 MW coal-fired units, the Lakeview site has been fully developed and no additional generating capacity is likely to be installed before 1995. Following the Watts from Waste Demonstration at this

station in 1978, it may continue to be used to burn refuse in addition to coal.

Lambton

Industrial emissions, particularly SO_2, are of considerable concern in the Sarnia Chemical Valley. However, if stack emissions and discharge of waste heat can be kept to acceptable levels and fuel oil is available, the Ontario Hydro property has potential to accommodate up to two 750 MW oil-fired units, in addition to the existing four 500 MW coal-fired units.

Nanticoke

The Nanticoke site will be fully developed when the present construction of eight 500 MW coal-fired units is completed.

Lennox

After completion of the four 500 MW oil-fired units now under construction at Lennox GS, there will remain a potential for two additional stations on the Ontario Hydro property. Of these additional stations, both could be nuclear, or one could be nuclear and the other fossil-steam. Current land use plans show part of the site allocated for a fish hatchery. If the fish hatchery is developed, then the fossil-steam station would need to be oil-fired as there would be insufficient room for a coal storage pile.

It has been known for some time that the waters of Lake Ontario at Lennox are a fish spawning ground. Thus, any future increase of generation on the site, will probably require extensive cooling water intake and discharge facilities in order to prevent undesirable thermal effects on the lake in this area.

Wesleyville

In addition to the projected four 500 MW oil-fired units at Wesleyville GS, an additional nuclear station could be built on the west half of the site.

Pickering

With the construction of Pickering GS "B", the site will have been fully developed to its ultimate capacity of eight 500 MW nuclear units.

Bruce

In addition to the 200 MW Douglas Point nuclear station, Ontario Hydro's current generating facilities under construction and planned for the site, i.e. Bruce "A" and Bruce "B", comprise eight 750 MW nuclear units. The property currently owned would permit the development of two additional stations which could be either fossil-steam or nuclear.

However, extensive investigations and monitoring of the possible effects of the installed and planned facilities will be required to establish whether the site could support additional generating capacity. It is envisaged that extensive studies on cooling systems and transmission would be required.

Darlington

In addition to the planned Darlington GS of four 850 MW nuclear units, the currently held property will permit development of two additional nuclear stations or one nuclear station and one coal-fired station. These would be subject to investigations and studies of the effects of the planned nuclear station and considerable new analysis of air quality if a fossil-steam station were proposed.

Thunder Bay

The present capacity is one 100 MW coal-fired unit, and two lignite-fired units of 150 MW each are scheduled for completion in 1979 and 1980. The site could accommodate an additional 600 MW. However, under current pollution control regulations, increased operational restrictions are expected.

(c) Important Considerations for the Next Station To Be Added to an Existing Site

Aquatic Environment

The pre-operational and post-operational studies on the hydrology, water quality and biology should have identified those areas of the aquatic environment which have or have not been influenced by the existing station.

Some of the most important considerations apply to both fossil and nuclear plants and include such factors as, interaction between thermal discharges and cooling water intakes; aquatic biota cropping level due to entrainment;

thermal influence on aquatic biota; and water current modifications. Surveys and studies at Ontario Hydro's existing stations along with similar work by other parties are providing an increasing amount of information on these subjects.

Atmospheric Environment

There are very few emissions to atmosphere common to nuclear and fossil fuelled stations, so additive effects need not be considered if the site is to accommodate the two different types of station. If both stations are of the same type an important consideration is the capacity of the environment to effectively disperse the stations' emissions so that acceptable levels are not exceeded due to the new generation.

Community Effects

Construction and operation of the next generating station will in some way affect the social and economic structure of neighbouring communities. This will be due mainly to another influx of workers, some with families, with the resultant increased demand on housing, consumer goods, and all types of governmental services. The latter include health, recreation, libraries, education, police and fire protection, and municipal administration. Other causes of social and economic effects will include another demand on local labour supply, additional local purchases of materials and services by the project, and increased traffic generated by project employees and material deliveries.

The degree to which the communities will be affected depends on the additional number of relocated workers and their accommodation and lifestyle requirements, the time lag between construction of the previous station and the next station, the present size and economic base of the communities, the ability of the communities to meet increased demands on services, and the condition and capacity of local transportation routes and facilities.

Construction and operation of fossil plants generally impose a lesser economic impact on neighbouring communities. They require a smaller work force, both for construction and operation, than required for a nuclear plant of equal capacity. Also, a higher percentage of the construction manpower and the operating staff, may be hired locally.

Egress

The effect of transmission egress would be included in the Environmental Assessment of any proposal to install additional generation on an existing generation site.

I. Study Zones for Future Thermal Generating Stations

The potential of the sites presently owned by Ontario Hydro to accommodate additional generating facilities has been discussed in the Section H.

With respect to new sites, initial studies of the shores of the Great Lakes and the St. Lawrence River to the Quebec border have been made and resulted in the delineation of zones that may have the potential for the location of major future generating facilities. The accompanying map (Figure 6.5-6) shows the study areas in southern Ontario within which these potential zones are located.

Additional studies have been initiated to delineate potential study zones along the shores of large inland lakes (e.g. Timiskaming, Nipissing, Wanapitei, etc.) and major rivers (e.g. French, Ottawa, Madawaska, etc.). Results of these studies will probably not be available for some time, possibly in 1977. Areas along the shores of northward flowing rivers such as the Abitibi, Mattagami, Missinaibi, etc. have not yet been studied.

Work is now underway on the selection of a generating station site on the North Channel of Lake Huron, and the acquisition of a generating station site near Atikokan.

J. Ontario Hydro Process for Selection of Generating Station Sites

Each area is examined to identify major constraints as to station siting. This leads to identification of zones which have the potential to accommodate generating stations. At the same time bands which have the potential to accommodate transmission lines, connecting the zone with the system, are also identified.

The generating station zones are displayed to the public and government agencies for review and comment.

Information received is considered together with environmental, legal, technical and cost considerations to identify potential sites within the zones.

These sites are evaluated and compared on the basis of available data. The public and government agencies are asked to comment on these comparative evaluations. Potential nuclear and heavy water plant sites are reviewed with the Atomic Energy Control Board for preliminary comment with respect to licensing considerations and guidelines.

Information and comments from government agencies and the public are incorporated into the final site selection. A report is submitted to Government recommending the specific site and describing the alternatives. This report is in the format of an environmental assessment.

The Government may approve the recommendation directly, or after it is reviewed by the Environmental Assessment Board in compliance with the Environmental Assessment Act.

The new procedures for site selection and project approval are being applied to the North Channel GS. The site selection process has now identified alternative sites and Ontario Hydro will shortly be seeking public views on the comparison of the alternatives. The requirements of the Environmental Assessment Act have been identified. The draft Environmental Assessment Report will be presented for discussion with the government during 1976.

7.0 PRINCIPLES OF TRANSMISSION PLANNING

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7.0 PRINCIPLES OF TRANSMISSION PLANNING

7.1 Summary

Section 7.0 describes the Ontario Hydro bulk power transmission system as it has developed into an integrated system. It also describes the way in which future additions to the system are planned, and what principles, criteria and constraints govern such future additions. The orientation of Section 7.0 is entirely electro-technical. The environmental implications, criteria, and constraints which govern system expansion are treated in Section 12.0

In common with most other major utilities in the world, Ontario Hydro has developed an integrated bulk power transmission system. This is a system in which all the main generating stations and load centres are interconnected by a high-capacity network of transmission lines and switching stations. This contrasts with the systems used in remote areas, in which each load centre is supplied from its own generation, and not interconnected with other load areas. The advantages of integration are reduced generation reserve requirements, economies of scale in generation construction, and reduced day-to-day operating costs. The chief disadvantage is a requirement for a somewhat more extensive transmission system.

In solving transmission expansion problems, it is usually necessary to take a "system" or "global" approach. However, it must be borne in mind that the components of the system, lines and stations, are themselves complex subsystems, requiring considerable detailed study and design. Furthermore, to control the system and its components, and to adapt to changing normal operating conditions and meet emergency situations, a sophisticated automatic control system is required. Ultimately, operation requires human intervention, and a staff of operating personnel is necessary to supply around-the-clock supervision.

Research and standardization play a large role in the selection of operating voltage levels for different parts of the transmission system. The reasoning behind the choice of 500 kV for the Ontario Hydro system is given in an appendix to this Section.

If the electric demand of customers continues to grow, whether at historic or reduced rates, an expansion of the supply system will be necessary. There are electro-technical limits, such as current carrying capacity and stability, which limit the capability of the present system to supply increasing loads with adequate reliability. In expanding the system, however, there are many trade-offs to be made between cost, reliability

and other factors. The process of planning transmission system expansion has four main steps:

- determine that additional facilities are required and their timing
- develop alternative systems for meeting the requirements
- evaluate the alternative systems
- select the most suitable alternative

Reliability analysis, always an important consideration in transmission planning, is assuming increasing importance. It is expected that contingency-testing criteria will be increasingly supplemented with mathematical probability techniques.

Important considerations in planning the expansion of transmission systems are the number of lines on a right of way and the rebuilding of existing facilities to a higher capacity. Combining a number of lines on a single right of way may be attractive from a land use standpoint but reduces reliability. Rebuilding of existing facilities to a higher capacity has been used extensively by Ontario Hydro but there are limits to the extent of its application.

While alternating current transmission has been used exclusively in Ontario, transmission by High Voltage Direct Current (HVDC) is an important technique for overcoming certain special planning problems. These include ultra-long distance transmission or interconnection of systems in adjacent areas, where solution by conventional alternating current methods is intractable or costly.

7.2 System Integration

A delivery system is required to transport electricity from generating stations where it is produced to the millions of individual locations throughout the Province where it is consumed.

Generally, individual customers are connected by subtransmission or distribution lines operating at voltages below 50 kV to area supply stations. These are supplied by transmission lines (nominally 115 kV, 230 kV and 500 kV) which have adequate capacity to supply several such stations. Some large industrial customers are supplied directly from the 115 kV and 230 kV lines. The transmission lines in turn are connected to terminal stations. The terminal stations are interconnected with one another and with the generating stations by additional transmission lines. Therefore, the

transmission lines may serve one or more of the following functions:

- to deliver electric power to area supply stations or directly to large industrial customers

- to interconnect terminal stations

- to deliver power from generating stations to the load area

This network of transmission lines permits a load area to be supplied from a number of generating stations.

This is known as an integrated system, and is the type used by most large utilities throughout the world. It contrasts with a system in which groups of customers are each supplied from a separate isolated generating station. The isolated system is the type often used in remote areas, such as Northern Canada.

Although the integrated power system requires more high-voltage transmission, it has been adopted for major systems because of the following advantages:

(a) Reduced generation reserve requirements for the same reliability of supply if generating unit sizes and type remain fixed.

(b) Reduced operating costs because generation with the lowest operating cost can supply most of the energy.

(c) Reduced capital expenditures from economies of scale (e.g. use of large generating units), more freedom in selecting the type of generation, and a more efficient construction program.

(d) Greater flexibility in locating generating station sites and in operating the generation.

The extent to which a system is integrated depends upon many factors requiring extensive cost, environmental and technical considerations. A fully integrated network would be one in which the total load at any time could be fully supplied from any adequate combination of generators connected to the network. Most systems, including the Ontario Hydro system, are not fully integrated. These systems have transmission limits which require that some proportion of the generation in an area be operated to permit supplying the full load in that area.

7.3 Major Transmission System Components

A. Transmission Lines

For planning and operating convenience, transmission lines are classed into four categories, according to their primary function.

(a) Bulk power transmission lines

These are the main lines delivering power from generating stations to receiving terminal stations. They form the interconnected integrated system described in Section 7.2. On the existing Ontario Hydro system some of these lines operate at 500 kV (500,000 volts), most operate at 230 kV, and a few operate at 115 kV. Almost all these lines are overhead.

(b) Area supply lines

These lines take power from the bulk power transmission system at the receiving terminal stations and transmit it to area-supply transformer stations located in or near cities and towns. The usual voltage levels are 230 kV or 115 kV. These lines are mainly overhead, but in large cities such as Toronto they are often placed underground.

(c) Subtransmission lines

These are a further step in getting the power to the individual customers. They transmit power in smaller quantities away from area-supply transformer stations to large customers and distributing stations in or near cities, towns and villages. The voltage levels are 44 kV, 27.6 kV or 13.8 kV. Some lines are overhead and others are underground.

(d) Distribution lines

These are the final stage in the distribution of power to individual customers. They usually are the wood or concrete pole lines routed along streets, concession roads, and back fence lines. In new residential subdivisions they are often placed underground. For distribution to groups of customers, the voltage level is usually 12.48 kV, 8.32 kV or 4.16 kV. For the final stage of distribution to the premises of individual customers, the voltage level is 120/240 volts for residential, 120/240 volts or 120/208 volts for small commercial customers or 600 volts for light industries.

The foregoing defines the categories and gives the voltage levels used in the majority of cases. However, there are

exceptions. For example, some large industries take power directly from the area supply lines at 230 kV or 115 kV. In large municipalities, recently-built distribution lines sometimes use voltages which would formerly have been classed as subtransmission voltages.

There are a number of standard voltage levels used throughout North America. For any given transmission line, the voltage used is determined partly by the amount of power being transmitted and partly by geographical location. The highest voltage, which is 500 kV in Ontario, is used where large amounts of power are being transmitted, for example on the bulk power system from a major generating station to a major load centre. Lower voltages are used, for example 230 kV, where the amount of power being handled is less. Examples are transmission from a smaller generating station or for area supply. Changing from one voltage level to another is accomplished with transformers which are located at stations on the transmission system. Voltage levels are discussed more fully in Appendix 7-A.

Power is moved from one place to another on a transmission circuit consisting of three conductors electrically insulated from ground and each other.

Some tower lines, called 1-circuit lines are designed to carry only one circuit. The three conductors of the circuit are carried horizontally or in triangular configuration as shown in Figures 8-1 and 8-2.

More commonly, 2-circuit tower lines, designed to carry two circuits, are used. The three conductors of each circuit are normally carried one above the other, as shown in Figure 8-2. This requires the tower to be higher than a 1-circuit tower of the same voltage. But a 2-circuit line can carry the two circuits on a right-of-way of about the same width as that required for a 1-circuit tower line of the same voltage.

In addition to the power conductors, most tower lines carry one or two lightning-protection conductors, which are attached without insulation to the highest points on the towers.

A number of other variations exist. For example, there are towers designed to carry four circuits at a voltage up to 230 kV. Also, at 500 kV, each of the three conductors in the circuit comprises a "bundle" of four closely-spaced conductors rather than a single conductor.

Overhead lines use air to insulate the three conductors of a circuit, and this requires a large amount of space. The insulation space can be very much compacted by use of oil-impregnated paper. This is the method used in providing

underground cable circuits. The major penalty for such compaction is a much higher cost.

B. Stations

Stations are required to integrate the transmission lines into a network. Stations perform the following functions:

- To provide points where power from several transmission lines can be combined and rerouted in different directions to loads

- To provide switching points for disconnecting faulted transmission circuits and permit re-routing of power along unfaulted circuits

- To provide points where the voltage level can be changed, e.g. from 500 kV to 230 kV, to suit a change in function from bulk power transmission to area supply transmission, or for other reasons.

A major station may include numbers of the following components:

(a) Circuit Breaker

This is a switch whose purpose is to connect and disconnect transmission circuits and transformers, as required during normally changing operating conditions or in emergencies when faults or short circuits occur. However, it must be carefully designed, since its duties are onerous. Most circuit breakers must sit for weeks or months on end carrying normal and emergency currents and be exposed to normal system voltages, but they must be ready to open quickly and automatically when a short circuit occurs on the system component they are protecting. The heavy currents which flow through the closed breaker during the first interval of less than 1/20 second after a short circuit occurs exert large mechanical forces on the circuit breaker parts and in addition heat up its electric contacts. During the next short interval of less than 1/20 second, the circuit breaker contacts must separate, an electric arc must be drawn between them, and then the insulating medium in the breaker (oil, compressed air, or sulphur hexafluoride) must flow in to extinguish the arc and interrupt the current. If the arc is extinguished too quickly, overvoltages will be produced on the system, which will stress the insulation. If the arc is not extinguished quickly enough, its heat will destroy the breaker. If the current being interrupted is beyond the designed capability of the breaker, the breaker will be damaged or destroyed. The designer of the

transmission system must ensure that the system is designed so that the short ciruit current cannot exceed the breaker capability. With large systems such as Ontario Hydro's, this can be a significant limitation on network design.

(b) Transformer

This is a static device which does not rely on moving parts to accomplish its primary purpose. It consists of a number of windings of insulated electric conductors mounted on an iron core, immersed in a tank of oil for insulation and cooling. For cost reasons the transformer may be designed to have as high a capacity as possible within limits of weight and dimensions set by railway or road transport equipment used to deliver it from the factory to the station. The transformer must also be designed with adequate insulation to stand normal voltages and the abnormal voltages which may result from lightning and circuit breaker action. It must have adequate current-carrying capacity to meet the system requirements without overheating. It may have voltage regulating equipment, which enables it to change one of its voltage levels upwards or downwards by about 10% to accommodate changing operating conditions.

(c) Capacitor

Capacitors are static devices which can be connected in series with a transmission circuit in which case they are called series capacitors or can be connected between the three conductors or phases of a circuit in which case they are called shunt capacitors.

Series capacitors are used to control the distribution of power flow on circuits connected to form parallel paths, to reduce the voltage drop on transmission circuits and/or to improve the system electric stability. Series capacitors have been extensively used on some systems, but they have not been found advantageous on Ontario Hydro's high voltage system to date.

Shunt capacitors are used to control voltage and to reduce transmission losses. In Ontario they have been provided in banks up to 30,000 kVA at subtransmission voltages and it is planned to install them in banks of 50,000 to 200,000 kVA for use on the 115 and 230 kV systems. For most banks, switches are provided so that they can be connected to increase voltage or disconnected to decrease voltage as appropriate. Up to the end of 1974 approximately 2,800,000 kVA of shunt capacitors were in-service on the Ontario Hydro system.

(d) Shunt Reactor

Shunt reactors are also used to control voltage and have been employed at voltages up to 500 kV. They have the opposite effect to capacitors, decreasing the voltage when they are connected and increasing it when disconnected. Up to the end of 1975 about 1,300,000 kVA of shunt reactors were in-service on the Ontario Hydro system.

(e) Phase-Shifting Transformer

Phase-shifting transformers provide another means of controlling the distribution of power flow. Because of their high cost and complexity their use on the Ontario Hydro system has been limited to interconnections with other utilities.

While the foregoing comprise the major elements of a transmission system, there are many other components which while small in physical size and power handling capability are essential to the operation and performance of the system. The more important of these are:

i) Current and voltage transformers for reducing the current and voltage of the high voltage lines to voltage levels which can safely be measured.

ii) Meters for recording and indicating such quantities as current, voltage and power at many locations throughout the system.

iii) Protective relays for automatically detecting faults in equipment and initiating signals to the appropriate circuit breakers to disconnect the faulty equipment. Probably the most sophisticated relaying systems are those used for line protection. This relaying must be able to detect faulty currents on a circuit over one hundred miles in length within 1/30 of a second or less. Yet the relaying should not trip for faults on other connected lines or equipment where fault current could be much larger.

iv) Excitation systems for generators and synchronous condensers. These systems function to control generator or synchronous condenser voltage and improve stability limits.

v) Speed governors for controlling the speed and power output of generating units by controlling the steam valves in the case of thermal units or the gate position in the case of hydraulic units.

vi) Load and frequency control systems for controlling the power interchange between interconnected systems and keeping the frequency of the system at the desired level.

vii) Communication systems for voice communication, remote control, coordination of protective relaying and other functions. Communication can be by open-wire line, cable, radio, power line carrier or microwave. Ontario Hydro's communications system makes use of its own facilities and also those of Bell Canada and the Telegraph companies.

The major components of a station are grouped together at lowest cost in a safe and compact arrangement to provide for electric security, and ease of operation with spacing and access for maintenance. The circuit breakers in this arrangement are grouped in a switching configuration which provides alternative conductor paths for power flow to and from the transmission line termination points. The power transformers are placed between the higher and lower voltage switching installations to which they are connected and are generally located adjacent to the station railway spur line to facilitate replacement in case of failure. Other components such as capacitors and reactors are located within or as close as possible to their required connection points. All the components are controlled and their functions monitored from buildings strategically located in the station complex to minimize interconnecting control cable runs as well as to provide suitable accommodation and ready access for operating personnel. In addition to housing the sensitive control, metering, protective relaying, together with associated service and battery equipment, the building may also accommodate facilities for the supervisory control of unattended satellite supply stations in the area.

7.4 Control Centre and Operators

All the equipment described in the previous section is used to supply the varying load imposed on the system by customer demand. Although much of the equipment is automated, it is necessary to apply considerable human intervention 24 hours per day, 7 days a week to ensure smooth operation during both routine and emergency conditions. To provide the human effort needed to meet the load demand with a high degree of reliability and safety and at the lowest operating cost is the responsibility of the operating staff in Ontario Hydro.

As of December 31, 1975, a staff of approximately 1,450 was engaged directly in operation of the system. These operators were located at 28 generating stations, 40 transformer and

switching stations, 7 Regional Operating Centres, and 1 System Control Centre. In addition to operating the stations where they worked, they were responsible for controlling 50 unattended generating stations and 169 unattended transformer and switching stations.

The overall direction of the high voltage system including the coordination of the outputs of all generating plants and the actual connections of system components is from one central point called the System Control Centre which is located in Toronto. This direction is in the main carried out through the Regional Operating Centres to the operators at the attended stations.

The System Control Centre is responsible for:

i) Monitoring the system to ensure that operating security limits are respected.

ii) Dispatching generation to ensure that minute-by-minute changes in load are met by the minimum-cost adjustment of generation.

iii) Controlling the intentional removal of equipment from service to respect cost and security policies.

iv) Buying and selling power with interconnected systems, establishing delivery schedules and price quotations in accordance with established policies.

v) Restoring the power system to normal, following a disturbance.

The extent of the Ontario Hydro power system is such that a large number of complex operational states are possible. The number and complexity of these states has increased significantly to the extent that the use of computers to assist in operation has become a necessity. In 1972 provision of a dedicated Data Acquisition and Computer System (DACS) was undertaken. A first phase of DACS is currently being placed in service. When completed, DACS will provide the System Control Centre staff with monitoring and analysis capability which will greatly facilitate discharge of their responsibilities.

It has also become apparent in recent years that the complexity in station operation is increasing rapidly as new and larger transformer and generating stations are added to the system. The development of computer assistance to station operators at thermal plants has reached a significant level and progress is being made now in the area of application of computers to hydraulic generating stations and transformer stations.

7.5 The Existing Transmission System

Figure 7-1 shows Ontario Hydro's existing transmission system as of December 31, 1975. It indicates the location of lines of 230 kV and higher voltage, and the location of the generating stations and major transformer and switching stations.

At the end of 1974, Ontario Hydro had the following route-miles of transmission lines:

500 kV	-	645
230 kV	-	5,208
115 kV	-	5,153

These lines represented an investment of $593,000,000 or 11% of the investment in electric power supply facilities.

The investment in transformer and switching stations at the end of 1974 was $693,000,000 or 13% of the investment in electric power facilities.

Figure 7-2 shows the location of the major load areas in Ontario. The concentration of load within the boundaries of the load areas shown accounts for about 73% of Ontario Hydro's December, 1975 East System peak load.

7.6 The Planning Process for a Transmission System

The process of planning a transmission system can be divided into four main steps:

- determine that additional facilities are required and their timing
- develop alternative systems for meeting the requirements
- evaluate the alternative systems
- select the most suitable alternative

Each of these steps is discussed below.

A. Determine that additional facilities are required and their timing

The requirement for and timing of additional facilities is determined by comparing the forecast peak and energy demands of the load with the capability of existing facilities to meet these demands. The capability of existing facilities and the requirement for new facilities are based on reliability criteria which are explained in Section 7.10.

Recent experience indicates that more than seven years will be required to plan and build a major transmission line. This time can be broken down approximately into periods as shown below. The timing cannot be stated with certainty because it depends on the time taken for public hearings and government review, over which Ontario Hydro has no control. In certain cases time may be saved by carrying on two steps concurrently. The figures below are considered minimum times.

	Estimated Time Period Years
Gather data, carry out public participation procedures, prepare a report recommending a plan, including hearings on alternative plans and approval of a plan	2 1/2
Gather data, carry out public participation procedures, prepare a report recommending a route, including hearings on route	2
Property acquisition, expropriation procedures, design and ordering of materials	2
Line construction (based on 100 miles)	1 1/2
Total	8

Any study of the need for additional facilities which may include a new transmission line must therefore be based on a forecast of conditions at least eight years in the future. If the additional facilities include a generating station on a new site, then the lead time increases to 12 or 13 years. Additions or changes to existing transmission and receiving terminal facilities not requiring environmental review normally require a lead time of two to four years.

The longer the lead time, the greater the range of alternatives open to the system designer. On the other hand, the longer the lead time, the less accurately will he know the factors which determine the need and the data used in assessing the alternatives. Clearly, then, it is essential to keep the lead time for alternatives short so that the forecast period is not unnecessarily lengthy; but on the other hand the study of future needs should extend far enough into the future to permit all reasonable alternatives to be considered.

B. Develop Alternative Systems

There are a large number of potential solutions to most supply problems. In the interest of efficiency and arriving at a solution in the available time, the planner may eliminate solutions that are theoretically possible but which are unreasonable because their lead time is too long, because they are too costly, or because the required technology is not sufficiently advanced.

The formulation of alternatives is a critical part of the process because:

(a) only a limited number of alternatives can be investigated in detail because of limits on time and manpower.

(b) elimination of an alternative at an early stage may mean it is very costly or impractical to consider it later.

(c) feasible alternatives may be overlooked and there is no way of ensuring that all the feasible alternatives have been included.

The development of practical alternatives requires a knowledge of the existing network, its capabilities and the provisions that have been made for its expansion. A long range planning framework for the expansion of the generation and transmission system is also required. The framework cannot be a detailed plan, but it should provide a guide for formulating current plans. Without such a guide, planning will be done on a short term incremental basis which may result in higher costs, lower reliability and greater environmental implications in the long run.

Every alternative considered must be investigated to ensure it meets the following technical requirements:

(a) it provides acceptable reliability

(b) it remains within thermal, voltage, stability, relay and short-circuit limits for a wide range of normal and emergency operating conditions that can occur over the lifetime of the facility. These limits and the techniques for investigating them are outlined in Sections 7.8 and 7.9.

Possible alternatives for providing increased transmission capability are:

i) Reconnect existing facilities

ii) Uprate or rebuild existing facilities.

iii) Install devices for voltage control such as series or shunt capacitors or reactors or synchronous condensers.

iv) Install generation rejection or load rejection schemes.

v) Locate new generating stations and stage the development of new generating units to avoid or reduce the required new transmission facilities.

vi) Build new interconnections or upgrade existing interconnections with other utilities.

vii) Build additional overhead or underground transmission lines and/or station facilities.

C. Evaluate Alternative Systems

Once a decision has been made on the alternatives to be studied, then a great deal of data must be gathered to permit their evaluation. Data are gathered in three major areas:

(a) Environmental data - This is outlined in Appendix 12-B and includes the human environment.

(b) Cost data - Such data normally includes differences in capital, operating and maintenance costs. Methods for comparing the cost of alternatives are outlined in Section 10.0.

(c) Technical data - While each alternative considered must meet all the minimum technical and timing requirements, there may be considerable differences among alternatives in technical factors such as:

i) flexibility to adapt to a change in forecast conditions

ii) reliability

iii) ease of operation

iv) risk in the development of new technology

D. Select the Most Suitable Alternative

Since there is no way of quantifying much of the data using a common measure, the selection of the most suitable alternative will usually require judgements. If an alternative affects a number of people, as is commonly the case with new major power

facilities, then those people may disagree with the judgements used in arriving at a final selection.

7.7 Transmission Loadings

The power used by an individual customer varies from instant to instant. The aggregate power used by all customers together, (called the system distributed load) also varies from instant to instant, but follows a more predictable pattern. For instance, the system load is low during the night when most industries are shut down. It rises rapidly between 6 A.M. and 8 A.M. to a relatively constant level during the morning, dips slightly during the noon hour, and rises again during the afternoon. It gradually drops during the evening, reaching a low about 5 A.M. The night time low is only about 60% of the peak load. The highest point during the day (the peak load) is reached between 5 P.M. and 6 P.M. in the winter, and generally earlier during the day in summer. The level of the peak load also has a predictable pattern through the year, being higher in winter than summer; and being higher with each passing year if growth in electric use continues.

Electricity cannot be stored in large quantities. Therefore, at every instant the generators must be producing in total an amount of power equal to the system distributed load plus the power losses in the transmission network. However, because of the integrating effect of the bulk power transmission network, it is not necessary for the output of each generator to follow the daily load pattern. Only the aggregate output of all generators must do this. Thus, as noted in Section 5.0, some generators can be operated at base load, some at intermediate load, and some as peaking generation.

The integrated transmission network must move power from generating stations to load centres. Because the transmission interconnects the load which is following one daily pattern and the outputs of individual generators which are following a different pattern, the daily pattern of power flowing in individual bulk power transmission circuits varies from instant to instant and follows a still different and much more complicated pattern. In some circuits, the power may flow in one direction for a few hours and then reverse direction over a period of a few minutes.

Not only does the loading on the individual circuits vary over a wide range during normal minute to minute operations, but sudden changes in loading can occur in emergencies. For example, a generator may become faulty and be disconnected from the system, automatically and suddenly. Because the system load has not changed, the output of the lost generator must be replaced immediately. This is done automatically by all generators on the system increasing their output slightly.

Thus, the power being carried by transmission circuits coming directly from the faulty generator makes a sudden large change, and for other circuits there is a sudden smaller change. Over the next few minutes, automatic equipment will readjust all generation, assigning the output of the faulty generator to generation held in reserve for the purpose, and the resulting power flows in transmission circuits will once more change.

As another example, a transmission line may develop a fault, requiring the automatic and sudden disconnection of one or more circuits without disconnecting the load. In this case there is no change either in the load or the generation. Therefore, the power which was flowing in the faulty circuit must continue to flow, somewhere else. It diverts instantly into other circuits, causing sudden changes in the power flowing on those circuits.

Thus there is a requirement that each circuit carry power loads which vary over a considerable range during both normal and emergency conditions. These variations may cause large power flows in some circuits at certain times. If the circuits are adequate for these stresses, all will be well. If the circuits are inadequate, there may be further automatic disconnections of circuits and resultant interruption of power flow to customers.

It is part of the planning function to predict which circuits may become inadequate in future, and to determine what reinforcement of the network is necessary to maintain safety and to reduce the chance of customer interruption to an acceptable level. The way this is done is the subject of the next three sub-sections.

7.8 Capability of the Transmission System

The electrical characteristics of a transmission circuit limit its capability to carry current and transfer power. These characteristics are resistance and reactance which impede the flow of current, and capacitance which requires the flow of non-productive current. The capability of the system is also limited by its security, which is its ability to withstand sudden changes in loading brought about by disturbances such as a lightning stroke to a transmission line or the sudden loss of a generating unit.

Because every conductor has resistance, energy is lost and heat is produced in the conductor whenever current flows. With overhead lines, this heat is dissipated from the conductor to the atmosphere, but in the process the temperature of the conductor is increased. The increased temperature has two undesirable effects:

- the conductor sags more between towers when it is hot thus requiring higher towers to maintain adequate clearances from ground.

- the aluminum in the conductor anneals at high temperatures, thus reducing the mechanical strength of the line.

These effects place limits on the maximum current which a line can be designed to carry. To some extent, the use of a larger conductor will permit loading to a higher current, because the larger conductor has lower resistance and hence lower losses. The amount of current which is required to flow in an emergency condition, such as described in Section 7.7, may determine the conductor size required.

In some cases, when account is taken of the value of the power and energy lost during normal operation, it is found that total costs are lower if a larger conductor is installed. This may lead to a higher initial cost, but lead to larger long-term benefits in view of the long-run reductions in the power and energy losses.

For underground cables, the maximum current is limited by the conductor temperature that can be permitted without degrading the oil-paper electric insulation. Current limits are lower than with overhead lines because the heat produced in the conductor is confined by the paper insulation, which is a good heat insulator as well as a good electric insulator. Thus cables must use much larger conductors than overhead lines in order to achieve reasonable current capabilities.

The reactance of a conductor is a characteristic which causes the voltage to be lower at the receiving end than at the sending end. To a degree this reduction in voltage can be compensated at the receiving end by installing such equipment as capacitors and voltage regulators.

The capacitance of a circuit results in a charging current, a non-productive current which must flow whenever the circuit is connected to the network. With overhead circuits this only becomes significant with very long lines, and need not concern us here. However, with underground cables more than about 10 miles long, the requirement for charging current begins to have an effect on the amount of power which can be transmitted. A 500 kV underground cable more than 20 to 30 miles long would become overloaded with charging current alone and could not be connected to the network unless shunt reactors were connected at its ends. In practice reactors are required for cables more than 10 to 15 miles long.

Stability is the ability of the generators to deliver constant power following a disturbance. It depends on the electrical

characteristics of the circuits, generators, and transformers, the configuration in which the circuits are interconnected and the effectiveness of the relaying system, circuit breakers and control systems. For example, suppose the network is operating normally with small changes occurring from moment to moment in load, generator output, and line load. Then lightning strikes a transmission tower, causing a fault to occur on one or more transmission circuits. The fault will cause sudden changes in the current and power in a large number of transmission circuits and will cause variations or swings to occur in the outputs of the individual generators. If the network is adequate and the fault is cleared quickly by automatic disconnection of the faulted line, these swings will gradually die down and the network will settle down to a new steady state with small moment-to-moment variations. If the network is inadequate, or the fault is not cleared quickly, the swings will build up, automatic equipment will disconnect some of the generators, and the load of some of the customers may be interrupted. To make the network adequate, it may be necessary to limit the current normally flowing in individual circuits by building extra circuits.

It can be seen that there are a number of factors which limit the current which can be carried by an individual transmission circuit. This permissible current may be less than the current required to be carried as described in Section 7.7. In such case, one or more additional circuits may be required, and these circuits may or may not be on the same tower line or follow the same route. These circuits, even if on the same tower line are generally controlled by separate switching at the stations, so that loss to the network in the event of a fault will be less.

7.9 Computation of Performance

If frequent interruptions to customers and groups of customers are to be avoided, the bulk power network must be adequate to withstand all normal and most emergency conditions which can occur. Because individual components of the network have limitations as described in Sub-section 7.8, it is necessary to have sufficient components, connected together in the correct configuration, to make the network adequate. Because of the time it takes to build new transmission lines, a method is required of determining their need well in advance.

The existing transmission system is subject to faults, and its performance under these conditions is recorded by meters and relays. Major disturbances are analyzed to determine whether the network performed as expected. Occasionally the system is tested by deliberately imposing faults on it. However, with a transmission system which is required to supply customer loads which grow year by year, it is necessary to predict whether the

system as expected to exist 5 to 10 years or more in the future will be adequate for the loads predicted to exist at that future time. If new facilities are required, it is necessary to start planning for them now, so that obtaining government approvals, design, construction, and testing can be carried out in their turn and that the new facilities will be ready for service when required. A method of simulating possible future network configurations and studying their performance is needed.

The simulation method used is to construct a mathematical model of the future supply system and to analyze it mathematically on a digital computer. The customer loads for a time 5 to 10 years in advance are predicted, locations for new generating stations and a possible future bulk power transmission network are assumed and the electrical characteristics (resistance, reactance, capacitance) of all the components are calculated. All this information is fed into a digital computer which calculates the voltages at all points on the system and the power and current flows in all circuits. The computer first calculates the voltages and flows for a condition where all circuits are connected to the network. (This is called the normal condition.) Then a fault or "contingency" (such as lightning striking both circuits of a double-circuit line) is simulated, and the behaviour of the model network over the next few seconds is calculated. This calculation predicts whether the proposed future system could recover from the disturbance or whether instability could result. It also predicts whether the post-fault current flows in all the circuits remain within the capability of the circuits. The results are analyzed by engineers to discover potential weaknesses in the network. Alternative systems are devised and their performance calculated.

The calculations and analyses of the future network alternatives will show the electric effect of possible alternative systems of future network expansion. The calculations will not show which of the alternatives should be selected. A decision on that must be made after performing additional analyses of reliability, cost, and environmental implications, and applying a large measure of judgement.

7.10 Reliability

It is possible to calculate whether or not the power supply network will be adequate to supply power to customers during and after the occurrence of any specific fault. But a further step is necessary. It is necessary to decide whether money should be spent to make the network adequate for any specific fault, or whether it should be planned to interrupt customer loads if the fault occurs. This decision depends partly on the cost of making the network adequate, partly on the probability

that the fault will occur, and partly on the probability that the particular load and generation pattern will occur. Analysis of the network to determine the probability that the network will become inadequate due to the whole spectrum of possible faults is called "reliability analysis".

Because a failure in the bulk power network would result in loss of power supply to a large number of customers, it is necessary to provide a high level of reliability in that network. The several thousand miles of transmission lines and the associated station facilities are subject to numerous hazards, such as:

- lightning
- excessive ice loads
- tornadoes and windstorms
- landslide and flooding
- aircraft striking towers or conductors
- land vehicles striking towers
- breakdown of insulation
- excessive equipment temperatures
- malfunction of protective relaying equipment
- faulty design, manufacture or installation
- spurious communication signals
- excessive vibration of sensitive equipment
- personnel errors
- malicious damage

It is necessary to make provision to supply the customers in a satisfactory manner, without overloading bulk power transmission lines, when line or station facilities are out of service due to failure or for routine maintenance. This is accomplished by installing more line and station facilities than would be required if the equipment were not subject to failure. Provision of additional facilities is sometimes called transmission "reserve".

A further aspect of transmission system reliability is known as "security". If the network has inadequate security it will be unable to recover from certain disturbances, large variations

will occur in voltages and power flows and usually within a few seconds after the disturbance, parts of the network will be forced out of service and customers' loads will be interrupted. The network is also said to lack security if it recovers from a disturbance but one or more circuits is overloaded.

To provide high reliability, it is therefore necessary to design the bulk power transmission network so that it will operate satisfactorily under all the varying operating conditions which occur from moment to moment, even with some of the facilities out of service, and so that it will have sufficient security to remain stable through reasonably foreseeable disturbances.

While it is not possible to predict when a disturbance will occur, it is possible to predict how often a common disturbance such as a line outage due to lightning will occur, on the average. This can be done by using probability mathematics. While some mathematical probability techniques are available for assessing whether networks have enough reserve, the sheer magnitude of the problem of assessing all the causes and effects of outages has made it impractical to develop a comprehensive computer program which can be applied to a power system as large as that of Ontario Hydro. Even those probability programs which are under development are adapted to analysis of reserve only, and will not be of use in assessing network security. It has therefore been necessary to adopt a more deterministic technique of evaluating the reserve and security of the network - the simulation method described in the previous sub-section.

The simulation method of contingency testing is used by most utilities in North America, and is a standard procedure of the Northeast Power Coordinating Council (NPCC), a group of utilities in Eastern Canada and Northeastern United States of which Ontario Hydro is a member. The NPCC document "Basic Criteria for Design and Operation of Interconnected Power Systems" lists the criteria which the members are required to use in testing their bulk power systems. It is included in Appendix 7-B.

With the contingency testing technique, the transmission network is subjected by simulation to certain carefully-selected severe faults. If the system is adequate for these faults it will likely be adequate for all other faults which occur with reasonable frequency. As an example, the NPCC criteria specify that the system must be designed so that for a simultaneous fault on both circuits of a 2-circuit line, occurring at a time when some other critical circuit is already out of service for maintenance, the system must remain stable and settle down to a new steady-state condition. For more severe faults, which have a lower probability of occurring, (such as loss of all lines on a right-of-way) the system should

be designed to limit the geographical extent of the network failure.

In future, mathematical probability techniques may be used more extensively in reliability analysis. Ontario Hydro and other utilities and consultants have done much work in the last few years in developing computer programs which will assess the adequacy of networks from a reserve standpoint and calculate the probability that the network will be adequate. Work is continuing.

7.11 Number of Lines on a Right-of-Way

When the electro-technical calculations described in the previous sections determine that several circuits are required between two stations, a decision must be made as to whether all these circuits should be on the same right of way or whether two or more rights of way should be utilized. This decision requires trade-offs between acceptable system reliability, effective land use, minimum adverse visual effect, and acceptable cost.

A decision must be made as to whether to use 1-circuit or multiple circuit construction. Use of 1-circuit construction results in the highest reliability. Use of multiple circuit construction results in more effective land use and usually in reduced visual effect with acceptable reliability and cost. On the Ontario Hydro system, use of 2-circuit construction is therefore usually considered preferable at 500 kV. At 230 kV use of 2-circuit or in some cases 4-circuit construction is most common, and 1-circuit construction has been rarely used in recent years.

The failure or outage of a circuit or line due to lightning or other cause is considered probable enough that provision is usually made in the bulk power transmission system so that instability in the network and interruption to customer load will not result from failure of one transmission line.

When several lines are located geographically close together, such as on the same right of way, the possibility exists that a single cause can affect several lines. Examples of such causes are:

i) tornadoes,

ii) conductor galloping in windstorms,

iii) insulator contamination due to local pollution,

iv) malicious damage by gunfire,

v) impact by aircraft.

The probability of occurrence is small, but loss of several 500 kV lines at once would cause widespread customer interruption. For example, loss of all lines emanating from a large generating station will result in loss of the output from that station. This will cause a shortage of system generation, and depending on the size of the station may result in interruptions to a large number of customers. Loss of all lines supplying a major load area may result in a complete interruption of several days to customers in that area.

Using a separate right of way for each 500 kV tower line, rather than locating several lines on the same right of way, would provide reliability against the occurrences just mentioned, but would have the following disadvantages:

i) land use would be higher,

ii) more property owners would be affected, since there would be more routes,

iii) towers would be visible from more locations,

iv) the cost would likely be more.

In view of these disadvantages it is considered that in most areas of the province, the level of reliability resulting from two or more lines on the same right of way is acceptable.

However, for the largest generating stations and the major load areas, it is considered that complete dependence on one right of way would cause too great an adverse effect if that right of way were lost, and some provision for a partial alternate supply is necessary. At the current state of the art, the trade-off between reliability, land use, aesthetics, and cost is largely a matter of judgement. In long range planning studies, the following assumptions regarding bulk power transmission are made:

i) 2-circuit lines will be used in preference to 1-circuit lines,

ii) several lines on a right of way will be permitted, but normally limited to two 2-circuit lines or three 1-circuit lines,

iii) Where the size of a generating station exceeds 10% of the system load, two rights of way will be preferred. If the first few miles of egress must be on one right of way for land use reasons such distance will be kept to a minimum.

iv) After permanent loss of all circuits on a right of way serving a major load area (more than 500 MW of load) or interconnecting major portions of the bulk power system, the remaining system must be capable of supplying 85% of the peak load in the affected deficient area assuming that the generation in the affected area is operating at an output calculated to be available 98% of the time.

On some rights of way, particularly near urban areas, it will be necessary to route 230 kV area supply lines and lower voltage distribution lines on the same rights of way as 500 kV lines. This may cause a deterioration in the visual aspects. It should not reduce reliability very much, because loss of the bulk power circuits may interrupt the power supply to the area supply circuits and in this event simultaneous damage to the area supply circuits will only increase the difficulty of repair.

7.12 Rebuilding or Replacing Existing Facilities

Over the years, Ontario Hydro has acquired considerable land for accommodating its transmission lines and stations. As land becomes scarcer, the question arises whether Ontario Hydro should be acquiring new land, or should be reusing its existing holdings by rebuilding or replacing existing facilities.

Ontario Hydro has done considerable rebuilding of transmission lines in the past, to transmit more power over the same land. Examples are:

(a) Between Lakeview GS and Manby TS an existing right-of-way, initially used at 60 kV at the turn of the century was rebuilt in 1961 with 230 kV circuits and is now adequate to carry the output of six units at Lakeview GS.

(b) On the eastern outskirts of London an existing 115 kV line built in 1910 on a narrow right of way was replaced in 1972 by a 230 kV steel-pole line to supply a new area supply station.

(c) Across northern Metropolitan Toronto, a 115 kV line built in 1950 as part of the first 60 Hz supply in the area was replaced in 1970 by a 230 kV line to augment the bulk power supply system.

Also there has been much rebuilding of stations to increase their current carrying capacity or voltage, with little or no increase in property size.

However, there are limits beyond which rebuilding is not feasible. Some of the reasons why a specific existing

transmission line cannot be rebuilt or replaced by new line are:

(a) The existing facilities may have an important and continuing use.

(b) It may not be possible to rebuild or replace the existing facilities without interrupting customer load for a period of several months.

(c) The existing right of way may be too narrow for the proposed new facilities, and widening may not be feasible.

(d) The existing right of way may not be environmentally suited to rebuilding. Many 115 kV lines built around 1910 were routed adjacent to roads for easy maintenance. Nowadays back lots are favoured for line routes.

(e) The new lines may be required to serve new loads or generating stations where there are no existing lines to rebuild.

The present 230 kV network serves two important purposes - providing the bulk power transmission system and supplying the area-supply stations. It is proposed to overlay the 230 kV system with a new 500 kV system, which will take over some of the bulk power transmission duties, freeing capacity on the 230 kV system for the growing requirements of area supply. Thus many of the existing 230 kV circuits have a continuing use, and it is not feasible to remove them from service to permit the right-of-way to be used for 500 kV lines.

7.13 High Voltage Direct Current

Electric utility systems throughout the world are almost exclusively alternating current (ac). This is so because ac generators and motors are of simpler construction than direct current (dc) equipment. Also in an ac system, the transformer makes it possible to use high voltages for transmitting power on the bulk power network and to convert to low voltages for utilization. Where customers require dc power such as for traction, steel mills, or electrochemical processes, they can produce it from utility ac power with rotating converters or electronic rectifiers.

Interest in dc has continued because of its potential to ameliorate some of the problems which must be accepted with large ac networks such as:

- ac networks with long transmission lines have stability problems

- ac networks supplying high concentrations of power in urban areas produce very large short circuit currents, requiring high capacity circuit breakers to isolate faults

- ac underground and underwater systems require compensating equipment every few miles to neutralize the charging current. This effectively limits the length of underwater ac links, because of the difficulty in finding locations for the compensating equipment.

However, ac has remained the basic mode of operation of the main system, and dc has only been used for special purpose links in utility networks.

Large high-voltage direct current (HVDC) systems only became practical in the 1950's, when controlled mercury-arc valves were developed for high-voltage applications. With these, it was possible to convert from ac to dc or dc to ac electronically on a large scale.

The first applications of HVDC were long underwater cables (Sweden to Gotland, France to England), where ac applications were not practical because of the high charging current for a long ac cable. There has been considerable development and use of dc throughout the world over the past 20 years and there are now more than 20 high-capacity HVDC links in service or in the contract stage. Many of these are underwater links (Italy-Sardinia, Vancouver Island, etc.), some are overhead links bringing power from a remote generating station to a load area (Manitoba, Zaire), one is a frequency changer (Japan), and one is a tie between two contiguous ac systems which cannot be interconnected by an ac tie for stability reasons (Quebec-New Brunswick). There is also a HVDC line which operates in parallel with an interconnected ac system (Western U.S.A.). The total capacity of the 13 links in service in 1975 is about 7,100 MW, less than half the present Ontario load.

The need for HVDC links on the Ontario Hydro system has not appeared in the past. There is a possibility that HVDC systems will be built in Ontario in future. The following recent developments point toward this.

- An interconnection at HVDC, operating in parallel with ac circuits has been placed in service in western U.S.A. and is providing satisfactory service

- A HVDC circuit breaker has been developed

- The development of thyristor valves promises better reliability and reduced costs.

Examples of possible applications in Ontario are a major interconnection with Quebec, and an expanded interconnection

between Ontario Hydro's East System and West System. These could also be viewed as parts of the proposed Trans-Canada grid.

Staff of Ontario Hydro have been following closely developments in HVDC for many years, through studies of technical literature, courses, membership on international committees, discussions with manufacturers, liaison with operators of existing HVDC systems (Manitoba Hydro, Hydro Quebec, and B.C. Hydro) and attendance at seminars.

8.0 TRANSMISSION

CONTENTS

FIGURES (Bound in Volume 2)

Appendices (Bound in Volume 2)

8.0 TRANSMISSION

Summary

This section discusses the status of EHV and UHV transmission, design criteria for overhead lines and stations, physical plant, costs, underground transmission systems and potential environmental effects of facilities. Appendices provide more detailed information on construction and maintenance procedures, property acquisition policies and electrical effects.

8.1 Overhead Lines

A. Status of Extra High Voltage and Ultra High Voltage Transmission

Voltages in the range from 345 to 765 kV are known as extra high voltage (EHV) and levels of 345, 400, 500 and 765 are the levels most commonly used.

The first 500 kV transmission line designed for commercial operation at 500 kV was placed in-service in the mid 1960's. This was Ontario Hydro's 228 miles of line running from Pinard near James Bay to Hanmer near Sudbury. Shortly thereafter, Hydro Quebec placed in operation 365 miles of 735 kV line, which at that time was the highest operating voltage in the world. By 1973, there were over 11,000 circuit miles of lines in service at voltages of 500 kV or higher in North America. In the 1960's and early 1970's considerable progress was made in developing transmission design technology which, under pressure for early design decisions, was applied on a case by case basis. The development was aided by the installation of a number of full scale research projects, including Ontario Hydro's Coldwater Project. By 1968, most basic design parameters had been generalized and consolidated so that reliable lines could be designed up to 800 kV without the need for any further experimentation.

It is generally believed that a voltage level above 765 kV and likely in the 1000 to 1500 kV range will be required on a number of systems in the world in the next ten to twenty years. This higher voltage level is known as ultra high voltage (UHV).

The major incentives to adopt UHV voltage levels will be similar to those which have led to increasing voltage levels throughout the history of the electric power industry. The incentives arise because of the need to transmit either larger amounts of power or over longer distances. They are:

(a) Reduction in the unit cost of transmission (economy of scale).

(b) Decrease in the numbers of lines and in total right of way requirements.

While there are no commercial installations of power facilities at the UHV level, there are a number of test installations throughout the world. Hydro Quebec's Institute of Research has carried out a test program to investigate the performance and determine desirable design parameters for 1200 kV lines. (Reference 8.1(6)). This voltage level was considered for the James Bay Project but they have now decided to use 765 kV.

Project UHV is an American high voltage transmission research program sponsored by the Electrical Power Research Institute and funded by the Edison Electric Institute, Bonneville Power Administration (BPA), the Tennessee Valley Authority (TVA) and other government agencies. This work is being carried out by staff of the General Electric Company in the United States (References 8.1(2), 8.1(5)). Project UHV was initiated in the late 1960's to provide technical data which would permit utilities to consider the installation of UHV facilities. Voltage levels up to 1500 kV have been studied.

In the early 1970's, the American Electric Power Company (AEP) and ASEA, a large Swedish manufacturer, in association with the Ohio Brass Company initiated a ten year research project on UHV (References 8.1(3), 8.1(4)). The objective of the program is to obtain fundamental knowledge essential to the development of major equipment and the design of systems, lines and stations in the approximate range of 1000 kV to 1500 kV. Research has also been carried out in Great Britain, France, Italy and the Soviet Union.

BPA announced in 1974 a proposal to construct two 1100 kV test lines in their Oregon service area to gather performance data for lines at this voltage level. One line, one mile long for mechanical testing, will be located in an area where weather produces extremes of wind and ice. The other line, two miles long, is for electrical testing. Data on radio and TV signal interference and audible noise levels will be gathered under all weather conditions. (Reference 8.1(7)).

Much of the work that has been carried out has been directed towards the following areas of transmission line design:

(a) Establishing limits for audible and radio noise.

(b) Establishing limits for electrostatic induction effects.

(c) Determining a suitable insulation design.

(d) Investigating techniques for live line maintenance.

Based on the work carried out to date, it is generally considered that it will be possible to design economically and environmentally acceptable UHV transmission systems.

The physical dimensions for a 1300 kV line extracted from Reference 8.1(1) are shown in Figure 8-1 along with similar data for an Ontario Hydro 500 kV 1-circuit line.

UHV transmission generally requires a larger number and larger size of conductors in each phase than EHV transmission. For example, Hydro Quebec's research at 1200 kV indicated they would require 6 x 1.832" diameter conductors in each phase on a 50" diameter circle (Reference 8.1(6)) while Ontario Hydro's 500 kV conductor arrangement uses 4 x .95" diameter conductors on a 28" diameter circle (20" square) as shown in Figure 8-1.

It is understood that Canadian utilities do not foresee the need for UHV in their systems prior to the 1990's. Similarly, in the United States, UHV is not expected to be required until the late 1980's.

B. Transmission Structures

Tower Types

Typical 230 kV, 500 kV and 765 kV towers used on bulk power systems are shown in the diagrams of Figure 8-2. These are known as rigid lattice towers.

Two 230 kV structures are shown, i.e., a 2-circuit and a 4-circuit configuration. The 2-circuit tower consists of one circuit on each side of the vertical shaft whereas the 4-circuit tower consists of two circuits on each side of the shaft. Each circuit is comprised of 3 phases with one conductor per phase. Grounded shield wires located at the top of all towers provide protection against lightning strokes.

The 500 kV 2-circuit structure is similar in general configuration to the 230 kV structure but each phase consists of 4 conductors forming a 20 inch square. The 1-circuit, 500 kV structure is referred to as a delta shape because the phase arrangement is triangular.

The 1-circuit, 765 kV structure is that used by Hydro-Quebec and is shown to illustrate its size relative to that of the lower voltage towers.

Effect of Line Angles

Only suspension (or straight line towers) are shown in Figure 8-2. In a transmission line, turns in the direction of the line (i.e., deflection angles) are taken by angle towers as

illustrated in Figure 8-3. The per mile costs (in 1976 dollars) shown in Figures 8-2 and 8-4 are based on a 10-mile section in which there are 58 suspension towers, 4 light angle towers, 1 medium angle tower and 3 heavy angle (or anchor) towers. This is representative of the average usage in southern Ontario. In northern Ontario, the spans could be longer and the relative number of angle structures less. Figure 8-4 illustrates the much higher cost of angle structures compared to suspension structures. From a cost standpoint, therefore, the number of turns in the line should be as few as possible.

Pole vs Rigid Lattice Structures

The alternative to a lattice structure is a pole type structure as illustrated in Figure 8-5. Pole type structures are considerably heavier and costlier compared to lattice structures as illustrated in Figure 8-4. Some people have expressed a preference for pole type structures from an aesthetic point of view.

Foundations

Figure 8-6 shows the more commonly used structure foundations. The augered or cast-in-place footing has a wide application in southern Ontario. Augered footings are not applicable in rocky soils or soils that are too weak to hold their shape until the concrete is poured.

The grillage type footing is made up of steel sections, usually rolled angles, channels and beams. Grillages are generally applicable for the lower range of footing loads and in some instances where augering equipment cannot be taken in to the site.

The pad and pier type footing is made up of steel reinforced concrete formed to shape. Pad and pier footings are suitable for heavy loads where augered depths would become impractical or where soil must be supported while concrete is being poured.

C. Electrical Design Criteria and Practices

Electrical phenomena associated with transmission lines cause electric and magnetic field effects in the space surrounding the lines. These effects are controlled to ensure public safety, to reduce to acceptable levels the interference with other public services such as radio and TV reception and to ensure the safe and reliable operation of the lines themselves.

The control of these electrical effects is achieved by designing the lines to meet certain criteria and by controlling

land uses beneath and immediately adjacent to the transmission lines.

This section briefly outlines the criteria and practices used by Ontario Hydro to control these affects and compares them with the requirements of the national standards embodied in the Canadian Electrical Code. Also included are typical right-of-way widths that may result from the application of these criteria and practices.

A more complete description of the electrical phenomena and their effects is given in Appendix 8-C together with results of some of the calculations performed for transmission lines discussed in this report. The Appendix also includes a discussion of recent studies carried out to determine the physiological effects of electric fields.

Clearances

National standards (the Canadian Electrical Code, Part III, CSA Standard (C22.3 No. 1) define minimum acceptable clearances for safe and continuous operation and protection of property. Ontario Hydro normally provides a margin of clearance over these code requirements. Figure 8-7 compares the vertical clearances of conductors above ground required by CSA C22.3 No. 1 and those provided by Ontario Hydro. It also compares the horizontal clearances from conductors to buildings required by CSA to the minimums provided by Ontario Hydro. The horizontal clearances are to be maintained when the conductor is swung due to wind. The swing calculations employed by Ontario Hydro and CSA are identical and the clearances are based on estimated transient voltages generated by switching operations.

Consideration is also given by Ontario Hydro to conductor swings that are possible during extremely high winds. Since conductor sag increases with tower span length, the conductor swing also increases, so that lines with long spans may require a greater width of right-of-way than those with short spans.

Electrostatic Induction

Energized electrical conductors are surrounded by an electric field. The strength of the electric field (expressed in kV/meter) depends on the voltage level of the conductor and the distance from the conductor to the object under consideration. It is independent of current flowing in the conductor. The electric field causes an induced voltage to appear on ungrounded objects (or persons) within the sphere of influence of the field. It is this induced voltage which sometimes causes a person walking under a transmission line to experience a slight electrical shock similar to that experienced when walking across a carpet.

Electric field strengths are not specified in the national standards, except as may be inferred from the provisions for minimum clearances discussed earlier and shown in Figure 8-7. The clearances provided by Ontario Hydro are greater than those specified by the national standards and hence the induced voltages are less than the permissible limits implied therein.

Ontario Hydro's design practice is to limit the electric field strength under the lines and at the edges of the rights of way to values appropriate to present or planned land uses. These limits vary along the rights of way as clearances to ground change because land usages change. The safety and acceptability of these limits have been established through experience with HV and EHV lines.

Radio Interference

Radio interference (RI) is generated by corona on various line components and by minute electrical discharges at small air gaps that may exist with loose hardware.

National standards (the Canadian Electrical Code, Part III, CSA Standard C108.3.1) define the tolerable interference levels during fair weather at a point 50 feet laterally from the outermost conductor at ground level. The prescribed levels are 50, 57 and 60 dB for 230 kV, 500 kV and 765 kV lines respectively. Ontario Hydro's criterion is to limit the maximum fair weather RI level at a point ten feet outside the right of way to 40 dB which at least meets or surpasses the national standards.

Television Interference

There are no requirements in the Canadian Electrical Code. Care is taken in the design of conductor hardware to eliminate discharges across small gaps resulting from loose connections, which is the major source of TVI during fair weather. TVI may also be generated by corona, but where RI levels are limited, TVI levels have not been a source of complaint.

Audible Noise

There are no requirements in the national standards with respect to audible noise and design limits have not been set by Ontario Hydro. Maximum noise levels (during heavy rains) for Ontario Hydro 500 kV lines are approximately 55 dB (A) at the edges of the rights of way. The noise level in a typical office is 50 to 60 dB(A).

Helicopter Patrol

Where patrol and/or maintenance of multiple line rights of way by helicopter is required, distances between conductors of adjacent lines must be sufficient to permit such operations to be performed safely.

D. Right of Way Widths

The criteria discussed in the preceding section result in typical right of way widths shown in Figures 8-8 to 8-11 inclusive for various numbers of 230 kV, 500 kV and 765 kV lines. The actual widths required for specific rights of way vary, depending on a variety of factors such as span length, conductor size and sag, the need for helicopter patrol or the need for fall-free spacing at the egress from generating plants.

E. References

8.1(1) F. Denbrock, K.R. Shah "UHV power lines can be built now" Energy International, pp 19-21, December 1973.

8.1(2) G.M. McAllister "UHV Transmission - A Status Report" presented at the CEA Transmission Section Meeting, Quebec, October 26, 1971.

8.1(3) "Transmission for the Future - A UHV Research Project" a paper received from ASEA.

8.1(4) H.C. Barnes, "The AEP-ASEA UHV research project - an international cooperative effort" presented at the American Power Conference April 1970.

8.1(5) S.A. Ammestrand, J.J. LaForest, L.E. Zaffanella "Switching Surge Design of Towers for UHV Transmission" IEEE Transactions on Power Apparatus and Systems, pp 1598-1603, July/August 1971.

8.1(6) N.G. Trink, P.S. Maruvada and B. Porrier "A Comparative Study of the Corona Performance of Conductor Bundles for 1200 kV Transmission Lines" IEEE Transaction on Power Apparatus and Systems, pp. 940-949, May/June 1974.

8.1(7) "BPA Latest to Try UHV", John Marks, Electric Light and Power, March 1974, page 4 (T&D Edition)

8.2 Underground Cable

A. General

Ontario Hydro uses two types of cable at transmission voltages of 115 kV and 230 kV; self-contained low pressure, oil-filled

(LPOF) which operates in the 15 to 75 psi range and high-pressure oil-filled pipe-type (HPOF) which operates at about 200 psi. Both consist of a conductor insulated with oil-impregnated paper and pressurized with oil to exclude air and moisture. There are advantages and disadvantages to both types as discussed in subsections B and C below.

A major disadvantage, common to both types results from the fact that the conductor, insulation and ground collectively act as a capacitor. A large quantity of the current carried by the cable is used for capacitive or charging current, reducing the amount available for active power. Because the charging current increases with length of cable, there is a critical length at which the power transmitting capability is reduced to zero. For a 500 kV oil-impregnated paper insulated ac cable, the theoretical critical length is in the 10-15 mile range and the practical length would be about 50% of this. Although capacitive current can be compensated by installing reactors at stations spaced every 5 to 10 miles along the cable route, these reactor stations are complex and costly and they reduce the reliability of a cable installation.

Although the probability of an outage on an underground cable is smaller than for an overhead line, should an outage occur it is likely that the cable would be unavailable for service for a longer period. For some applications, it may be necessary to allow for this unavailability and build additional underground cable circuits.

Cable circuits are spaced to improve heat dissipation, limit the amount of damage from dig-ins and provide access for maintenance.

B. Self-Contained, Low Pressure Oil-Filled Cable (LPOF Cable)

These cables are sheathed individually in the factory with either an aluminum or lead sheath and covered with an extruded plastic jacket for corrosion protection. Because they are self-contained they can be laid with wide separation between phases to improve heat dissipation and so increase current carrying capacity.

Their major disadvantage is that usually almost a mile of trench must be opened at one time for cable laying. The sequence of installation is such that cable is laid from joint bay to joint bay, while the previous section is being back-filled and the next section is being excavated. Because of interruption to streets and traffic this system is not generally used in city streets.

C. High-Pressure Oil-Filled Pipe-Type Cable (HPOF Cable)

These cables are shipped from the factory with a moisture barrier but without a metallic sheath on reels sealed with a plastic sheet and slightly pressurized with nitrogen to exclude air and moisture. Three cables forming one circuit are pulled together into one pipe.

As the pipe can be installed well in advance of cable pulling it is only necessary to open a few hundred feet of trench at one time, and consequently there is relatively little interruption to traffic. The strong steel pipe provides excellent mechanical protection from dig-ins. However, since three cables are close together in the pipe, mutual heating effects are more pronounced than with self-contained cables. Furthermore, the additional losses in the cable shield and the pipe require a larger conductor than LPOF cable for the same current carrying capacity. As a result, pipe-type cables cost somewhat more than self-contained low-pressure oil-filled cables for equivalent current carrying capacity.

D. Compressed Gas Insulated Cable

Gas insulated transmission systems have been installed in recent years at voltage levels up to 345 kV. A 500 kV system has been installed recently by Bonneville Power Administration. Generally, each phase of these gas insulated systems consist of two concentric metal tubes, one the conductor and the other the sheath and these are held apart by insulating spacers. The insulating medium used to date is sulphur hexafluoride (SF6) usually at pressures in the order of 30 to 50 psig.

All installations to date are short, and total service experience is short. The IEEE Insulated Conductor Committee Listing of Cables shows ten compressed gas insulated cable installations in North America at the end of 1973, totalling less than one mile. The first system was energized in 1971.

The major advantages of compressed gas insulated cables, compared with paper insulated cables are, longer critical length because of lower capacitance, lower termination costs and higher potential power ratings. However, because factory produced lengths are short, many field-made joints are required and these must be made under very clean conditions. As line lengths increase, the advantages due to lower termination costs are overcome by higher cable costs.

E. DAMUT AND DIGUT Systems

A feasibility study on a Ducted Air Medium Underground Transmission system for operation at 230 kV was initiated by

Ontario Hydro in 1972. Very briefly stated, the circuit design is based upon the use of three 12-inch diameter aluminum tube conductors arranged in triangular configuration on approximately 3-foot centres and housed within a 9-foot diameter corrugated steel duct with air as the insulating medium. Potential advantages are lower costs, higher capacity and simpler maintenance compared to conventional cable.

Prototype testing has been done on the main duct components but a further five to ten year period will be required for development of joints, conductor support insulators and terminations to produce a complete assembly for full electrical testing before possible subsequent use in the Hydro network.

Consideration is also being given to the development of a Ducted Inert Gas Underground Transmission system for operation at 500 kV using similar basic design but with an inert gas as the insulating medium. However, no laboratory tests have been conducted to date.

F. Cryogenic Cable

There are two basic types of cable in which the conductors operate at very low temperatures. One is the cryo-resistive cable where conductors are operated at the temperature of liquid nitrogen, i.e. - 169 C. The other is the superconducting cable which utilizes exotic materials, such as niobium, for the conductor and operates at temperatures below -250°C. Both systems require complex refrigerating plants, which consume large amounts of power.

Both systems are experimental and are not likely to be available commercially before 1990. When available, they may lead to lower cost of underground transmission but only when large blocks of power, (several thousand MW on a single circuit) are to be transmitted. Outage durations may be greater than with conventional cable designs because it takes time to reduce the system temperature from ambient to operating temperatures.

8.3 Comparison of Overhead Line with Underground Cable

When connecting an underground line to an overhead line, the major design requirement is to provide a cable which will transmit the emergency load of an overhead line. Because of the large loads to be transmitted, it is sometimes necessary to install an underground cable system with more than one cable per phase.

Figure 8-12 shows the right of way widths required to install 230 kV cable circuits which will carry an emergency load of 940

MVA per circuit. These are equivalent to 230 kV overhead lines using a 1.6 inch diameter conductor. The estimated cost of installing a 2-circuit 230 kV overhead line is $300,000 per mile. A 2-circuit 230 kV LPOF cable system using two 1500 kcmil copper conductors per phase is estimated to cost $3,400,000 per mile. A 2-circuit 230 kV HPOF cable system using two 2750 kcmil copper conductors per phase is estimated to cost $6,400,000 per mile. The above costs are in 1976 dollars. In both cases, the costs of facilities required to terminate the cable circuits at overhead lines or stations, such as potheads and pressurizing equipment have not been included.

The above LPOF cable costs only apply to installations in rural and suburban areas. The installation of LPOF cables in congested areas normally involves the use of ducts and manholes to reduce length of trench that must be opened at any one time. This would result in costs close to those shown for an HPOF installation.

Figure 8-13 shows the right of way widths required to install 500 kV LPOF cable circuits which will carry an emergency load of 3460 MVA per circuit. This matches the summer emergency rating of the 500 kV overhead circuits. The estimated cost of installing the 500 kV 2-circuit lines shown in Figure 8-13 using three 3800 kcmil conductors per phase, is $16,000,000 per mile compared with an estimated installation cost of $600,000 for a 2-circuit overhead line. Because of the larger number of conductors per phase that would be required, Ontario Hydro has not considered HPOF cables for use at 500 kV.

Figure 8-14 shows a comparison of the quantities of material required to install the 230 kV and 500 kV underground cables and the overhead lines described above. It is evident that cable installations require massive quantities of material as compared to overhead lines.

8.4 Transformer and Switching Stations

The area required to accommodate a 500 kV transformer and switching station will vary from about 60 to 400 acres including an allowance for landscaping. The 60 acre size is based on the use of compact gas insulated switching equipment. Although we have a high degree of confidence in this type of switchgear, at this time there are no installations in the world of the size and voltage we have purchased for the Parkway Belt stations. Accordingly, its further use at 500 kV or at a higher voltage will be contingent on successful experience being gained, as well as other factors such as future costs and availability.

The compact switchgear employs sulphur hexafluoride (SF6) gas which is non-toxic and non-flammable. Its high dielectric strength allows significantly reduced insulation distances as compared with air. The components of this type of switchgear such as circuit breakers, disconnecting switches, potential transformers and bus are enclosed in metal housings. The housings are maintained at ground potential and are sectionalized to accommodate the switchgear components in separate gas filled compartments. The environmental and safety aspects of SF6 gas are discussed in Appendix 8-D.

Stations are usually located at the intersection of transmission line rights of way, within the areas determined by environmental, ecological and social considerations. All station sites will be landscaped so as to be compatible with the adjoining surroundings. Strategic soil mounding around the site perimeters, together with co-ordinated tree planting, will provide effective visual screening of the stations.

The need to provide for prompt replacement of faulted power transformers at any time of the year requires railway access to the station. The heavy shipping weights of transformers, which can be up to 350 tons, restricts their movement on public roads and highways and it is not possible to move them by road during the spring breakup period. Where sites are not located adjacent to existing railways the necessary interconnection by spur lines to the sites will be accommodated, where possible, on a transmission right of way to avoid additional land severances. Access to public roads will be required for transportation of material and personnel during the construction of the station. After completion, traffic to and from the station will be limited to operating and maintenance vehicles.

All sources of continuous noise generated by station equipment will be adequately muffled so that the noise level will be equal to or less than the ambient level in the neighbourhood. Conductor and hardware installations are designed to reduce voltage gradients to levels which will ensure that radio and T.V. reception at any adjacent residences will not be adversely affected by station equipment.

Costs of stations will vary depending upon the number of transmission lines being terminated, the number of transformer banks and how they are switched and connected. The complex nature of the station design and the many variables requires each individual installation to be estimated separately. The Parkway Belt 500 kV stations are estimated to cost between thirty and sixty million dollars each.

The following paragraphs give more detailed description of site selection criteria, environment considerations of station

components and alternative station switching arrangements that can be utilized for 500 kV and 230 kV system transformer stations.

A. Site Selection Criteria

The location of a station in a particular area is established by the convergence of transmission lines. However, the need for the lines and stations is determined by a system plan which is designed to meet either local area or provincial needs for additional electric supply facilities. The selection process for station sites is carried out together with the transmission route selection process and takes into account the following factors:

(a) Economic studies of alternative station and transmission line arrangements.

(b) Railway spur access for the transportation of large power transformers.

(c) Access to public streets or highways for operating and maintenance personnel.

(d) Compliance with government community plans and local bylaws.

(e) Possible disturbance to established residents and communities.

(f) Effects on the ecology.

(g) Existing and possible future use of the land required for the station.

(h) Natural features and land contours which lend themselves to drainage and landscaping purposes.

(i) Suitability of soil strata for supporting station installations.

(j) Soil resistivity and measures needed for the safe grounding of electrical equipment.

(k) Federal Ministry of Transportation Regulations for hazards to aircraft with respect to microwave and transmission line towers.

(l) Communications Canada, Department of Communication stipulations to prevent radio and television pattern interference.

These studies involve government ministries and agencies, general public and interest groups from an early stage in the process.

B. Environmental Considerations

(a) Transformers

Ontario Hydro has been purchasing 750 MVA 500/230 kV 3-phase autotransformers with core construction which guarantees a audible noise level not in excess of 84 dB. The installation of masonry acoustic enclosures will further reduce this level to 54 dB. Through normal attenuation the sound level is reduced to an acceptable value at the boundary of the station site. The policy for Ontario Hydro's new stations is to keep the sound level of transformers to a value which will not exceed the ambient level at any adjacent residences.

Retaining oil pits with sumps are constructed around all power transformers as an environmental protective device to contain spillage and provide a means of recovery in the event of the rupture of the tank or radiators. As a fire prevention measure the pits are filled with gravel to restrict oxygen to spilled oil which may have been ignited as a result of equipment failure.

Similar treatment for sound reduction and control of possible oil spillage is carried out for shunt and series reactors when they are needed.

(b) Circuit Breakers

Noise occurs on opening an airblast circuit breaker as the high pressure air is exhausted to the atmosphere after passing through the current interrupting chambers. This noise which is like a sharp report and lasts momentarily can be reduced by the fitting of mufflers. Breakers may be operated many times while being checked into service and then are seldom operated thereafter. However, some units used to switch capacitor or reactors may be operated on a more regular basis. During checking into service and maintenance, measures are taken to limit the impact of noise due to frequent breaker operations by limiting such operations to daytime working hours. Gas and oil insulated switchgear breakers have different and less sharp noise characteristics in their operation and are not as noticeable as airblast units.

(c) Capacitors

Capacitor installations at stations usually comprise compact stacked assemblies of individual and self-contained capacitor units to make up the required bank size. To date the impregnating insulant used in capacitor units is a synthetic non-flammable liquid of a non-biodegradable polychlorinated biphenol compound. Special measures are taken to protect the environment from this insulant which is known commercially as askarel. Procedures have been implemented that require regular inspection to detect any leakage and the prompt removal of the insulant when it occurs. (See Appendix 8-D)

(d) Emergency Service Supply

Normally the station-service supply is obtained from transformers connected to the high voltage system. On site, station service generation is sometimes needed as back-up supply, especially at stations where only switching facilities are installed. The prime mover which is usually a diesel engine can be a considerable source of noise. The noise of these machines is significantly reduced by the provision of acoustic housings and exhaust silencers. Operation, however, will be on an occasional basis for test purposes except for emergency situations when the normal source of station service supply has failed.

(e) Corona Effects - Radio and Television Interference and Acoustic Noise

Interference problems are avoided by controlling the surface voltage gradient on the station buses with a proper choice of conductor size, spacing and bundling. Also, station bus hardware and equipment is kept corona free when operated at the maximum system voltage through the use of streamlined hardware designs and the application of voltage grading rings.

C. Station Arrangements

The following arrangements are used by Ontario Hydro in the design of its 500 kV and 230 kV stations.

(a) Three-level, high-profile, open bus arrangement with flexible strain bus used for line take-offs. This design however, is limited to lower fault currents than (b) or (c).

(b) Two-level, low-profile, open bus arrangement using rigid tubing bus exclusively.

(c) Gas (SF6) insulated switchgear and bus work.

These station designs require widely different site areas. The differences in site dimensions and relative area requirements for a specific 500 kV or 230 kV switching element, which consists of a three or four breaker diameter and its associated buswork is as follows:

Switching Element	Width Ft.	Length Ft.	Relative Area
500 kV			
Three level, open bus	220	585	100%
Two level, open bus	420	550	179%
SF6 gas insulated	30	120	3%
230 kV			
Three level, open bus	110	325	100%
Two level, open bus	180	380	192%
SF6 gas insulated	25	65	5%

The typical assembly of a number of the above 500 kV and 230 kV switching elements together with transformer and transmission line terminal arrangements for a large terminal station can be observed from Figures 8-15, 8-16 and 8-17.

D. Switching Structure Profiles and Landscaping

The three-level bus switchyards for 500 kV and 230 kV are 96 feet and 52 feet high respectively. The 96 foot height makes the 500 kV switchyards imposing when seen from close up and readily visible on the horizon since the average woodlots found in Southern Ontario are about 50 to 70 feet in height. High level switchyards are therefore difficult to treat effectively with landscaping. Low profile structures have been developed to overcome this difficulty by reducing 500 kV and 230 kV switchyard heights to 50 feet and 29 feet respectively. Figure 8-18 illustrates typical elevations for 500 kV switchyards, high and low profile, and SF6 switching buildings. This Figure is reproduced only as a simple elevation and does not illustrate the full vista of the high level strain bus mass as seen by an individual viewing the total station. The final landscaping will include many more trees and shrubs than are illustrated. Most future air insulated 500 and 230 kV

switchyards are therefore expected to be designed as two-level switchyards except where particular site size constraints require the use of a high-profile three-level switchyard.

E. Gas Insulated Switchgear

The large size of air-insulated transformer stations is due primarily to the wide separation required between exposed high voltage components and between the components and ground. Additional clearances are also necessary to permit the use of heavy equipment for maintenance.

Substantial overall size reductions can be achieved by enclosing switchgear and buses in gas filled metal ducts which form safety barriers at ground potential. With the use of high dielectric strength sulphur hexafluoride gas (SF6) a duct diameter of 12" is possible for an operating voltage of 230 kV and 24" for 500 kV. Depending on the switchgear manufacturer's design, the SF6 gas which is non-toxic and non-flammable is used at pressures of up to 90psig. (See Appendix 8-C). Since a gas insulated station has all its high voltage components inside grounded enclosures, it can be accommodated in a confined area.

More than one hundred gas insulated stations in the 70 kV to 420 kV range are in commerical service in Europe. Some installations have been in service since 1967. Similar type switchgear at 115 kV to 500 kV has been installed or is on order in North America. There are also installations in Singapore and Japan. It is noted that most of these installations serve local loads in urban areas and are relatively small. The application of this type of installation to major terminal facilities such as the Parkway Belt stations, differs from these foreign stations in that the latter are not critical for system reliability.

Costs of particular elements of gas insulated switchgear approach twice the cost of the similar particular elements of air insulated switchgear at voltages below 230 kV. However, the extremely compact size of the SF6 switchyard results in important cost reductions in the facilities (site, roads, buildings, structures, control cables) associated with the switchgear especially at voltages above 230 kV. Since the major portions of this gear are assembled in the manufacturer's plant, field labour costs should also be reduced. Improved manufacturing methods and volume production are expected to bring equipment costs of SF6 more in line with those of conventional equipment costs in the next decade.

Gas insulated switchgear has a major effect on the size of switchyard areas and the entire station site. Gas insulated 230 kV switchgear occupies an area approximately 5% of that required for conventional high profile outdoor switchyards. In the case of 500 kV, it is about 3%. The reduction in total station site area is less than that for the individual switchyards because space for transformers and overhead line entrances is not significantly reduced.

Based on the compact nature of this switchgear and the climatic conditions found in Ontario, it appears prudent at present to install this switchgear in buildings. The building will provide a superior environment for erection, operation and maintenance independent of weather. The Parkway Belt stations are being designed to terminate most of the 500 kV transmission circuits directly on the switchgear building. This will improve the overall appearance of the station installation by eliminating the heavy anchor line structures that would otherwise be required.

F. Safety

Station switchyards and associated buildings are designed with equipment and buswork arranged in straight forward configurations with spacing to provide for the maximum safety of operating personnel. Adequate clearances are maintained to live parts. Walkways, both indoors and outdoors, are designed with alternative means of approach and escape. All stations where the facilities are not completely enclosed in a building, such as in rural areas, are encompassed with protective fencing for exclusion of the public. Chain link fencing, six feet in height, topped with three strands of barbed wire, is used around such stations.

G. Station Costs

There is little difference in total costs between high and low profile conventional stations for either 230 kV or 500 kV switching installations. There is also no appreciable estimated difference in total costs between 230 kV conventional and gas insulated switchgear stations. At the present time 500 kV gas insulated stations are estimated to be approximately fifteen percent lower in cost than equivalent conventional stations. However, these comparisons do not take into account property costs or construction of stations in rugged terrain. These factors could have a considerable effect on the cost comparisons in favour of gas insulated stations. Indications based on the experience in European utilities are that

substantial cost savings are possible in the maintenance of gas insulated switchgear as compared with conventional air and oil insulated equipment.

8.5 Effects of Transmission Facilities (Lines & Stations)

It is Ontario Hydro's objective to make a positive contribution to the quality of life of the people of the province by providing a reliable supply of electrical energy to meet Ontario's needs. The Corporation actively acknowledges the necessity of its locating, building, operating and maintaining transmission facilities in a manner which ensures the maximum net benefit to the province, region and community. This means reducing, to the greatest practical extent, any adverse effects those facilities might have on environmental conditions.

Ontario Hydro recognizes that high voltage transmission facilities, wherever located, cause some changes in the existing environment. Changes within the natural or man-modified environment are brought about by:

(a) Acquiring land or property rights to accommodate the facilities;

(b) Installing the facilities (including clearing and preparing construction sites and access routes, delivering materials, building tower foundations, assembling and erecting towers, stringing conductors, laying counterpoise);

(c) The physical presence of the facilities;

(d) Operating the facilities;

(e) Maintaining and repairing the facilities;

(f) Managing the land on which the facilities are located.

Because of the diversity of environmental conditions across the province, the potential for changes resulting from the introduction of transmission facilities differs from one area to another as regards what might be altered and to what extent. This potential for change can be predicted from a knowledge of both environmental conditions and standard design and implementation specifications.

The significance of any change lies in the effects that change might have, either directly or indirectly, on the quality of life of the people inhabiting or utilizing that area and of the people of the province or region as a whole, now and in the future. In general, such potential effects fall into one or more of three major categories:

(a) Ecological Effects

Changes in the quantity, quality or diversity of ecologically interdependent components of the natural environment (i.e. air, water, soil, plant life and animal life) can affect those biophysical and biochemical processes which are essential to the maintenance of healthy ecosystems and fundamental to the quality of life of the people of Ontario.

For example, compaction or rutting of surface soils by the passage of heavy construction equipment thereover, or the mixing of soil layers during excavation or site preparation activities, can inhibit or divert the movement of groundwater and limit the availability of soil nutrients to plant life. The removal or reduction of plant cover in areas of potentially erodible soils during installation or maintenance activities can result in accelerated soil erosion, thereby depriving those areas of their life-supporting nutrient base and depositing the eroded material elsewhere. Deposition of this material in a water course can detrimentally affect the quality of the stream or river by increasing turbidity and sedimentation. The removal of shade-giving trees from alongside coldwater streams can result in increased water temperatures and consequent decreased oxygen levels therein. Removing plant cover from areas of organic soils (i.e. wetlands), which act as natural water storage reservoirs, can reduce the storage capacity and change downstream flow characteristics. This can result in spring flooding or decreased summer flows downstream.

Furthermore, any of the aforementioned examples of disturbances of soils, water or vegetation, as well as the physical presence and operation of the transmission facilities themselves, can affect the suitability of the terrestrial or aquatic habitat for animal life by prohibiting or interfering with physiological processes or behavioural patterns related to feeding, reproduction, migration, etc.

(b) Socioeconomic Effects

In a positive sense, perhaps the most significant socioeconomic effects of additional high voltage transmission facilities result from their efficient and reliable delivery of electrical power - an essential contributor to the lifestyle of the vast majority of Ontarians and to the economy of a growing province - from expanded or new generating stations to load centres.

However, other changes resulting from the introduction of high voltage transmission facilities may detrimentally affect the social and economic welfare of some individuals, businesses and communities in the province by reducing the availability of natural resources upon which they rely for their living, by limiting the structural facilities which accommodate their activities, or by interfering with the use of those resources or facilities.

As a result, such locally and provincially important pursuits as food production, timber production, sand and gravel extraction, recreational activities, and residential, commercial or industrial development may be affected to some degree, both at the time the facilities are introduced and thereafter for as long as the facilities are in place and operating.

On an individual basis, severance of properties, placing of towers thereon, removal or relocation of buildings, etc. can create the potential for partial loss of financial investment and can interfere with the future plans of people so affected. For many parts of the province official land use plans, restrictions and policies exist, and violation of or conflict with these can adversely affect provincial, regional or local planning objectives.

Increasing construction and maintenance costs by adding new facilities, increasing line lengths and angles to avoid potential environmental problems, managing environmentally sensitive areas affected by facilities located therein, etc. can increase the cost of electrical power to Ontario's consumers.

(c) Psychological Effects

All of the aforementioned ecological and socio-economic effects of transmission facilities, whether actual or simply imagined, can have psychological effects on people. From a positive standpoint, most people in Ontario find comfort in the confidence that a reliable supply of electricity will be available when they need it. Conversely, the realization that equally essential natural systems and resources can be depleted or degraded, or the fear that personal ownership rights, health and safety might be in jeopardy, albeit for the benefit of Ontarians as a whole, are disturbing to many people.

A further important adverse psychological effect of introducing transmission facilities results from the changes they impose on the overall appearance of the landscape - the "visual effect". Each part of the

landscape of Ontario has a distinct "character" dependent on the unique combination and interaction of its component elements (e.g. topography, vegetation, water, man-made structures). The addition of new elements (e.g. towerlines) to, or the deletion of existing elements from, that landscape will result in changes to the perceived character of the area. The effect of such changes will depend on the value which people place on the particular landscape as a result of its diversity, uniqueness, utility, "beauty", etc., now and in the future.

Ontario Hydro attempts to reduce the potential adverse effects of its transmission facilities by:

(i) Openly planning the location, design and mode of implementation of needed facilities to avoid, as much as possible, the risk of causing adverse environmental changes and to comply with overall provincial, regional and local planning objectives - BEFORE THE FACT;

(ii) Implementing design specifications and construction, operation and maintenance procedures which will reduce to the greatest possible extent the occurrence and magnitude of adverse changes in areas where the risk of their occurring persists - DURING THE FACT;

(iii) Employing remedial or compensatory measures where necessary to alleviate unavoidable effects - AFTER THE FACT;

The implementation procedures and corrective measures used in standard practice by Ontario Hydro are described in Appendices 8-A and 8-B. Where unique unavoidable situations involving high risk of environmental effects are encountered, special designs, procedures or measures may be developed during the planning stage or improvised as necessary on site.

The study process for new transmission facilities includes a comprehensive comparison of the implications of all technically and economically feasible alternatives satisfying system needs, to arrive at that alternative which provides the maximum net benefit to the province or region. This process is described in Appendix 12-B.

CONTENTS

FIGURES (Bound in Volume 2)

9.0 INTERCONNECTIONS

9.1 Summary

This section discusses the advantages and disadvantages of interconnections, the history of interconnections between Ontario Hydro and neighbouring utilities, and the plans for future use of interconnections.

Interconnections have many potential advantages in the areas of improved system reliability and reduced costs. These advantages have consistently outweighed the disadvantages.

Provided each of the interconnected systems is not continuously short of generating capacity, possibilities exist for using interconnections to increase the reliability of the interconnected systems and to enable reductions in their generating capacity. In the extreme, these alternatives are mutually exclusive. That is, if the systems take maximum advantage from the increase in reliability, no generation reductions are possible; and conversely, if sufficiently large reductions are made in generating capacity, no increase in reliability will result. However, it may be possible to achieve some of both these benefits at the same time.

Possibilities also exist for increasing the reliability of the transmission systems and reducing transmission capacity. However, in some cases, interconnections may result in an increase in internal transmission.

Ontario Hydro has used its interconnections primarily to import firm power and to increase its generating system reliability. If capital funds permit, it is proposed to continue this practice in the next few years. If capital funds are insufficient to enable installation of Ontario Hydro's proposed generating capacity, it will be necessary to rely more heavily on assistance from interconnections. The latter situation is considered to be undesirable over the next eight years, for two reasons:

(a) Indications are that within a few years generation reserves at the time of peak loads may be very low in Quebec and the neighbouring States.

(b) In times of emergency power situations in the United States, government action could reduce or eliminate the assistance provided by the United States systems.

It is believed that it is unlikely that government action in the United States will result in the opening of the

interconnections. This is because the interconnections benefit the United States systems.

Reduced costs arise primarily from day-to-day reductions in operating costs, including purchases and sales of temporary excess capacity.

In addition, interconnections provide the opportunity for making firm purchases and sales, and for coordinated development of generation in neighbouring areas. This is discussed in Section 6.1 I.

Ontario Hydro proposes to continue use of its interconnections, to continue its ongoing studies on the expansion of interconnection capacity, and to profit where possible from reserve savings, firm purchases, coordinated development, and operation.

9.2 Introduction

The transmission lines which directly connect adjacent electric utilities are called interconnections.

For many years Ontario Hydro has been interconnected with the Great Lakes Power Corporation in the Sault Ste. Marie area of Ontario, Hydro-Quebec in Quebec, Manitoba Hydro in Manitoba, the Detroit Edison Company in Michigan and the Niagara Mohawk Power Corporation and the Power Authority of the State of New York (PASNY) in New York. In most cases these interconnections are connected to the bulk power networks of the co-operating utilities, and power may flow in either direction from moment to moment. The networks of Ontario Hydro, Manitoba Hydro, Great Lakes Power, Hydro-Quebec's Abitibi System, Detroit Edison, Niagara Mohawk, and PASNY are interconnected in this way and form part of a large power grid. This power grid joins together most of Central and Eastern United States and the Canadian provinces of Saskatchewan, Manitoba, Ontario, New Brunswick and Nova Scotia. Because of stability considerations, Hydro-Quebec cannot operate in parallel with this large power grid. However, portions of Hydro-Quebec's system can be isolated from its main system and interconnected to the Ontario Hydro system. This has enabled deliveries of power from Hydro-Quebec to Ontario. A similar procedure can be adopted to enable deliveries of power from Ontario to Quebec.

9.3 Advantages and Disadvantages

A. Advantages

(a) Increase in System Generating Reliability and/or Reduction in Reserve Generation.

As noted in Section. 5.0, it is impossible to design, construct, and operate a generating system to be completely reliable. There is always some chance, however small, that the generating system cannot completely supply the load. This chance depends primarily upon the planned level of generation reserves, whether the actual load is substantially greater than the forecast load, whether the generation in an operating condition is substantially less than the forecast amount, and whether supplies of fossil and nuclear fuels are adequate.

If two systems are interconnected, there is some chance that when one is unable to completely supply its load, the other may, at that time, have surplus generation available which it can use to supply power to the first. This assistance could enable the first system to reduce or eliminate the load interruptions which it would otherwise have to impose on its customers. At other times, the situation might reverse, with the second system receiving assistance from the first. There will also be occasions in which both systems are unable to supply their own loads at the same time. In such cases, neither system would be able to offer assistance to the other.

Because of this situation, two kinds of possibilities arise by virtue of an interconnection:

i) Each of the systems can achieve an increase in reliability

ii) One or both utilities can deliberately reduce its own reserve generating capacity and depend upon the other for assistance.

<u>Increase in Reliability</u>

Figure 9-1 illustrates the possibility of improvement in reliability which can result from a system such as Ontario Hydro interconnecting with an identical system, with neither system reducing its installed generation. The data in the figure are obtained by application of Loss of Load Probability (LOLP) programs similar to those described in Section 5.0 and Appendix 5-B. The figure shows the change in reliability as the interconnection capacity between the two systems is increased. It assumes that the generation and load levels in each of the systems remain the same when the interconnection is made. Three cases are shown, corresponding to three alternative reliability levels in each system when they are not interconnected.

It is evident that interconnecting these systems reduces the loss of load probability and therefore improves the

reliability of each system. The relative improvement is less if the loss of load probability with zero interconnection capacity is high.

Reduction in Reserve Generating Capacity

Figure 9-2 illustrates the possible reduction in reserve requirements resulting from the same interconnection arrangement, i.e., of the Ontario Hydro system with an identical system. In this case, instead of using the interconnection to improve reliability, it is used to maintain a constant reliability with lower generation reserves on each system. Three cases are shown corresponding to three alternative levels of reliability. From Figure 9-2 the following data can be derived for the Ontario Hydro system:

		Required Reserve Level				Possible Reductions in Required Reserve	
		No Interconnection		With Interconnection			
Case	LOLP	MW	% of Load	MW	% of Load	MW	% of Load
(a)	100/2400	3381	13.4	2631	10.2	750	3.2
(b)	10/2400	4636	19.4	3562	14.3	1074	5.1
(c)	1/2400	5692	25.0	4265	17.6	1427	7.4

Since a saving in construction of new generation may be possible, this alternative may appear attractive. However, it requires that the systems depend on each other in order to achieve the required reliability. If the interconnection capacity exists, the main elements of risk are that either or both of the systems may have reserves substantially less than the required level because of errors in load forecast or inability to install generation on schedule. Also, government action may restrict the interchange of energy. It is possible that either or both of the systems may actually end up with poor reliability; and this might require seven or more years to remedy because of the lead time for generation.

In the extremes, the alternatives shown in Figures 9-1 and 9-2 are mutually exclusive. That is, if the systems take maximum advantage from the increase in reliability, no generation reductions are possible. On the other hand, no increase in reliability will result if sufficiently large reductions are made in reserve generation capacity. However, it may be possible to achieve a portion of both these types of benefits at the same time.

Figures 9-1 and 9-2 deal with the increase in reliability of peak supply. Under some circumstances there will also be an increase in the reliability of energy supply. This would not be the case during periods of shortages of fuel which affect both of the systems.

Figures 9-1 and 9-2 should be regarded as illustrative only. Generally speaking, the benefits would be less than they indicate. This is because the LOLP analysis excludes many factors which are discussed in Appendix 5-B, and others raised later in this section.

(b) Diversity Exchanges of Power

Summer-Winter Diversity

In Ontario, peak loads occur in the winter and there is generally more reserve generating capacity in summer. In much of the United States, peak loads occur in the summer and there is generally more reserve generating capacity in winter. Therefore, there are opportunities for seasonal interchanges of power, to the benefit of all parties. For example, surplus Ontario Hydro power may be purchased by United States utilities during their summer peak period, and sold back to Ontario Hydro during its winter peak period. Long-term arrangement for interchanges is another possibility for financial savings in the planning of generation requirements, at the cost of some reduction in reliability. Another possibility is use of interconnections to achieve savings in the cost of maintenance.

Several years ago, Ontario Hydro engaged in diversity exchanges with Michigan on a trial basis. It turned out that, at the time of the diversity return to Ontario, the Michigan winter reserves were less than forecast, and the diversity return had a lower reliability than expected. Diversity exchanges have therefore been replaced with summertime sales. There is seasonal diversity between Ontario Hydro and systems further afield, such as New York City and Chicago. However, Ontario Hydro does not believe it can rely on these systems for diversity exchanges to reduce its generating capacity program because of

(i) limitations in transmission in intervening systems.

(ii) possible United States government action to restrict energy transfers.

(iii) If they are short of power, the intervening systems will have "first call" on the power available for exchange.

Daily Time-Zone Diversity

Since Ontario, Quebec, New York and Michigan are all on Eastern Time there is no appreciable diversity between their daily peak load periods. Diversity does exist between Ontario and other parts of Canada but the benefit to be gained by Ontario from daily diversity exchanges with them is small because

(i) The other systems are much smaller than Ontario.

(ii) There is a trend toward flattening of the daily load shape, and therefore the diversity in daily peak loads is expected to decrease.

(c) Advance or Joint Development - By making a firm agreement for sale over the interconnection extending over a period of a few years, one utility can install generating capacity in advance of its own need and sell it to another utility who can postpone installation of capacity on its system. This may be advantageous in the case of a major hydro-electric development where a large number of units are to be installed. Power is now purchased under short-term contracts from Quebec and Manitoba on this basis.

(d) Reduction in Transmission Requirements and Transmission Losses - Usually there is a reduction in losses. Under some circumstances there is a reduction in requirements.

(e) Reduced Operating Reserve

Since each party to an interconnection has access to his neighbour's operating reserve, and both parties are unlikely to require the reserve at precisely the same time, the amount of operating reserve which must be carried by each system can be less than it would have to carry if operating separately. This is an important advantage of interconnections because of the large daily saving it produces. To make this saving requires only a day-to-day mutual commitment by the parties to the interconnection.

(f) Improved Reliability Against Catastrophes - The interconnections reduce the probability of interruption of load due to such major contingencies as:

- interrelated multiple outages or reductions in generating or transmission capacity.

- extreme weather effects.

- latefall in the in-service dates of new facilities.

- shortages of critical materials such as heavy water or fuel.

- malicious damage or sabotage.

- strikes.

- loads being higher than forecast.

(g) Economy Transactions - It sometimes happens that one utility has idle generating capacity which can produce energy at a lower cost than some of the higher cost units on the neighbouring system. Under these conditions a scale of power on the interconnection can provide both parties with cost advantages.

(h) Frequency Stability - With the present interconnection covering the eastern half of North America, it is possible to maintain system frequency much more constant than could be accomplished with a non-interconnected system. The sudden change in frequency which occurs on failure of a generating unit is very small on a large interconnected system. This means motor speeds are more constant, which is important to a few industrial users.

B. Disadvantages

The major advantages just enumerated are obtained at the cost of some disadvantages.

(a) Changes in government policies may seriously restrict the value of interconnections, and effectively and unpredictably eliminate many of the advantages.

(b) Interconnection facilities must be installed and expanded as the utilities grow in size. In addition some increase in transmission to the point at which the interconnection line terminates may be required.

(c) Organizational complications result from the need for constant co-operation among utilities on planning, operating, scheduling and billing matters.

(d) Each system loses some autonomy in its planning and operation.

(e) Occasionally, a severe fault on one system will be

reflected through the interconnection into another system, causing some interruption of load.

(f) It is not feasible to use frequency reduction as a method of load curtailment.

C. Ontario Hydro's Position

Interconnections have many potential advantages, which fall mainly in the areas of increased system reliability and reduced operating costs. These include the possiblity of purchase of power during emergencies, prevention of widespread system outages upon the occurrence of severe contingencies, cost savings in day-to-day operation, and the possiblity of profitable power sales or purchases. There are also disadvantages, but these are outweighed by the advantages.

Ontario Hydro proposes to continue use of interconnections, to study the need to expand interconnection capacity, and to profit where possible from available firm purchases and from co-ordinated development with other systems in Canada and the United States.

One potential advantage of interconnections is the possibility of reducing generating reserves in Ontario by relying on assistance from other systems. By taking this action Ontario Hydro would become dependent on assistance from other utilities for maintaining a desirable level of reliability. Ontario Hydro does not feel it can avail itself of this advantage, because it does not believe that, in the next five to ten year period, utilities in adjacent areas will have enough reserves to make such sharing feasible. Furthermore, in the case of the United States utilities, Ontario Hydro fears that if the United States generation or fuel shortage reaches the state of a national emergency, the U.S. federal government may prohibit or restrict export of electricity to Canada.

However, it is possible that the shortage of capital funds will prevent Ontario Hydro from installing the amount of generation it considers it needs, and reliance on interconnections may become necessary, with the attendant risks being accepted.

9.4 History of Exports and Imports with United States, 1950 to 1975

Figure 9-3 shows Ontario Hydro net electric energy generated from coal imported from United States and net electric energy exports to the United States since 1950. The graph shows the energy imported in the form of coal has for some years exceeded the electric energy exported. Ontario Hydro is now dependent on United States coal for a large portion of its electric

energy supply. For electric energy export, this graph reflects the variations over the years in resource availability, requirements for emergency assistance and opportunities for profit.

Initially, Ontario Hydro had limited export capability with Niagara Mohawk using the 69 kV, 25 Hz tie lines at Niagara. Also, at times, power was exported at Cornwall using a 60 Hz circuit designated HM3 and operating at 115kV, which was rented from the Cedars Rapids Transmission Company.

Ontario Hydro's first major interconnection with the United States was made in 1953, when interconnections were built to the Detroit Edison system at Windsor and Sarnia. This was followed by an interconnection with Niagara Mohawk at Niagara in 1955. Interconnections with PASNY were established in the St. Lawrence area in 1958 and at Niagara in 1961. With Detroit Edison a third interconnection was established in 1966 and a fourth is under construction.

Almost immediately after the first two interconnections with Michigan were placed in-service in 1953, Ontario Hydro started buying emergency assistance to offset low water condidtions and the subsequent major failures involving the total Hearn plant in 1954. Although the quantities were small by today's standards, this assistance was of critical value at the time. Even under these adverse conditions, some export sales were possible at other times of the year during spring freshet and low load conditions. By the late 1950's the situation had reversed. Resource conditions, particularly stream flows, were favourable in Ontario. Niagara Mohawk had lost the output of the entire Schoellkopf generation plant as a result of a rockslide in the Niagara gorge. Large sales, mostly from hydraulic sources, were made to displace fossil-fuelled generation in New York and Michigan or to provide capacity assistance to Niagara Mohawk.

In the mid 1960's with very poor water conditions and commissioning problems at Lakeview GS electricity purchases usually exceeded sales. In 1968, for example, Ontario purchased emergency assistance from the United States to meet capacity shortages on 81 occasions in amounts up to 550 MW. Meanwhile coal purchases for thermal stations were rising rapidly. In the early 1970's, the load-resource situation deteriorated in the neighbouring United States systems and improved in Ontario. With favourable water conditions in Ontario, and the excellent performance of Pickering GS, Ontario Hydro had both surplus capacity and United States coal available most of the time to assist the hard-pressed American utilities. In late 1973 and early 1974, the Arab oil crisis added a new factor. The American systems purchased energy almost continuously whenever surplus generation was available to displace their oil-fired units. The assistance from Ontario

Hydro, using American coal, was undoubtedly a significant factor in easing the effect of the oil crisis in the Northeastern United States. In December, 1974, Ontario Hydro, with five 500 MW units out-of-service for an extended period, again required assistance, and a total of 510 MW of reserve capacity was purchased from the United States.

In 1975, largely as a result of the recession in the United States, the situation again changed suddenly and export sales dropped to about one-third the record 1974 quantities. With almost no load growth in 1975, the American load and capacity balance had improved so that only occasional assistance was required throughout the year to cover equipment outages or to displace higher cost generation.

9.5 Export Policy

Exports to customers outside Ontario are defined under the following three classifications:

Firm Export - Export sales which are given approximately equal priority with firm loads in Ontario.

Interruptible Export - Export sales which have a lower priority than Ontario loads and which would be interrupted to protect the reliability of supply in Canada.

Inadvertent Equichange - Offsetting inadvertent or unscheduled exports and imports of electricity which are a natural result of operating two or more systems in parallel. These equichanges do not involve any net export of energy from Canada and are not classified as "sales".

Ontario Hydro does not at present supply firm power directly to utilities or end users outside Ontario, except as a matter of "border accommodation" to certain customers in the United States who are difficult or impractical to supply from an American utility but can more easily be served from a Canadian utility and vice versa. There are three exports and two imports to Ontario of this type. The largest is a sale of about 30 megawatts to the Ontario-Minnesota Pulp and Paper Company at International Falls. The total of these firm exports by Ontario Hydro represent less than two-tenths of one percent of the 1975 installed capacity.

Future firm exports, if any, would be a matter of negotiation between the parties concerned and would be considered in terms of the overall merits of the specific proposal. Any contract for such exports would require the approval of the Provincial Cabinet and, in the case of exports to the United States, the National Energy Board. At a meeting of the Board of Directors

of Ontario Hydro on May 27, 1974, the following policy on the export of surplus interruptible power was approved.

"In order to obtain the benefits of improved quality of service, improved reliability, and reduced cost of service to Ontario Hydro customers that are provided by the necessarily-reciprocal agreements for participation in the interconnected network, it is the policy of Ontario Hydro to export surplus interruptible power in accordance with the following:

"(a) to provide emergency assistance to the maximum extent deemed consistent with the safe and proper operation of its own system and with its prior obligations to other Canadian systems;

"(b) to take advantage of opportunites for profitable sales at times other than emergencies in such quantities as deemed desirable, having due regard for conditions on the Ontario Hydro system;

"(c) to obtain a fair and economic return for the services provided and to maximize the longer term economic gain to Ontario, taking into account all applicable costs incurred in Canada and having due regard to the possibility that Ontario Hydro may need to purchase in future under the same conditions;

"(d) to adhere to the Corporation's policies on the conservation of energy and to any applicable governmental rules and regulations, including those relating to the use of resources, environmental restrictions, priority of supply and quantities that may be exported."

Any export of power to the United States, even equichange, is subject to authorization by the National Energy Board. The minimum requirements for granting an export license, as stated in the Board's 1974 Annual Report, are as follows:

> "Applicants for licences to export power must satisfy the Board that the energy proposed to be exported will be surplus to reasonably foreseeable Canadian needs.
>
> "To ensure that export prices are just and reasonable, an applicant must also satisfy the Board that the price will cover the cost of producing the power and transmitting it to the border, that it will not be less than the price to Canadians for comparable service, and that it will not be markedly less than the lowest cost alternative to the purchaser. The value to Canada of related imports is also taken into account."

Hydro policy on export to the United States has been the subject of much controversy during rate review hearings and public participation meetings. Opinions of intervenors range from banning export because of air pollution to constructing generating stations specifically for firm export.

9.6 Import Policy

Ontario Hydro is prepared to purchase power from other utilities when this is advantageous. At present Ontario Hydro purchases firm power from Quebec and Manitoba, but not from United States utilities.

Adjacent regions in the United States have in recent years been experiencing severe difficulties in obtaining the following:

(a) the necessary approvals for constructing new generating and transmission facilities,

(b) gas, oil and low sulphur coal to run existing plant, and,

(c) the necessary capital to build new facilties.

In view of these conditions, it is unlikely that firm power at an acceptable price and reliability level could be purchased from United States utilities in the foreseeable future. Possible future firm purchases from Quebec and Manitoba are being investigated, as described in section 9.11.

Also from time to time power is purchased from other utilities, including utilities in the United States on a short term interruptible basis.

The import of electricity is not subject to National Energy Board licensing.

9.7 Cost Analysis

Interconnections do not lend themselves to long term cost analysis because, in the absence of long term agreements for firm power sale or purchase, the tangible benefits cannot be estimated far in the future. Many of the benefits come from daily operating cost savings, which depend on operating policies and can be estimated only a few years in the future. The tangible benefits from non-firm interchanges can be substantial, but variable as in the export to the United States, where net profits were $55,000,000 in 1974 and $20,000,000 in 1975. Past experience has shown tangible benefits to be significant in most years, but this is little

help in forecasting. Also some major benefits such as improved reliability, cannot be estimated in financial terms.

On the other hand, the investments necessary for most of Ontario Hydro's interconnections have been generally small. They have involved two or three circuit breakers, a regulating transformer, and a few miles of transmission line. The cost of this is shared by the two utilities involved.

Therefore, most of Ontario Hydro's interconnections have involved a relatively small capital investment to gain benefits which cannot be quantified over the long term. The decision to install them has been made largely on a basis of intangibles and projection of past experiences.

If future Ontario Hydro interconnections involve large expenditures for internal transmission, more evidence of benefits may be required before a decision is made to proceed.

9.8 Interconnections with Quebec

Ontario Hydro has had major interconnections with Quebec since 1928. These were initially established to import power on long-term contracts of up to 44 years duration. They are located on the lower Ottawa River near Ottawa, and at the interprovincial border between Montreal and Cornwall. Hydro Quebec now supplies Ontario with firm power by disconnecting generation from its system and connecting it to the Ontario system. Ontario Hydro can now assist Quebec in emergencies to the extent that the generation in Quebec can be disconnected from the Ontario system and reconnected to the Quebec system. In addition Ontario Hydro can assist Hydro Quebec by isolating some Ontario generation on the Quebec System.

If the present firm contracts are not renewed, Ontario will be able to provide only limited support to Quebec in emergencies. The Ontario transmission system is not designed for easy isolation of major blocks of generation at Saunders or Lennox for export to Quebec. Furthermore, until transmission is installed in Eastern Ontario, any removal of facilities to supply Quebec would jeopardize the supply to Ottawa. Interconnection by isolated generation does not provide the operating flexibility which is achieved on our other interconnections where the systems operate in parallel. However, direct interconnection of the main systems of Quebec and Ontario would require costly transmission additions within Quebec to provide adequate transient stability.

There are also interconnections between Quebec's Abitibi system and Ontario Hydro's system in Northeastern Ontario. These interconnections are used mainly to reduce cost of operation of hydraulic storages and to transfer power in emergencies.

During the next few years, Ontario Hydro expects to provide assistance to Hydro Quebec's Abitibi system to meet forecast deficiencies in peak power and energy. By 1980, Hydro Quebec expects to have completed a 765 kV line to interconnect its main system with its Abitibi system. At that time power exchanges between Ontario Hydro and Quebec's Abitibi system will only be possible by isolated generation.

A list of existing interconnections is shown in Figure 9-4.

Daily operation of these interconnections is carried out under the terms of an Interconnection Agreement. The Agreement makes provision for firm import into Ontario, sharing of generation reserves, interchange of power for economy or in emergencies, wheeling (transmitting power from Southern Quebec through Ontario to Northern Quebec), co-ordination of maintenance, and co-ordination of development.

Of the long-term firm contracts, only one for 187 MW is still in effect, and it expires November 1, 1976. However, there is a contract for 1000 MW which commenced on June 1, 1975 and runs to May 31, 1977.

Straight numerical addition of the capacities of the interconnections with Quebec listed in Figure 9-4 would indicate an aggregate capacity of 2720 MW. However, because of system transmission considerations the limit for transfer to Ontario is in the range of 1300 to 1500 MW, and the limit for transfer to Quebec is 300 to 500 MW. Unless transmission is added, the limits will decrease in future years because of load growth near the border.

9.9 Interconnection with West System and Manitoba

Because of the large distances and small population, development of an interconnected system in Northern Ontario occurred later than in Southern Ontario. Isolated systems of Ontario Hydro and private companies in Northeastern Ontario were integrated by Ontario Hydro transmission lines and eventually interconnected with the main Southern Ontario system in 1950. The area around Sault Ste. Marie is supplied by a private company, Great Lakes Power Corporation, which was interconnected with Ontario Hydro in 1960. Ontario Hydro's West System supplying the area from Marathon to Kenora developed as an isolated system. It was interconnected with the Manitoba system in 1956 and with Ontario Hydro's East System in 1970.

A major addition to the interconnection with Manitoba was made in 1972 when two 230kV circuits were built from Whiteshell, Manitoba to Kenora to allow for a firm purchase of power by Ontario. Now Ontario Hydro's East and West systems operate in

synchronism with the system of Great Lakes Power Corporation and with Manitoba, Saskatchewan and most of eastern and central United States. The interconnections provide a transmission loop around Lakes Huron, Michigan and Superior. Because this loop permits power to "circulate" around these lakes creating the danger of overloading the interconnection circuits, it has been necessary to provide control of the circulating power by installing phase shifting regulating transformers at Whiteshell, Manitoba.

Ontario Hydro has a firm contract for purchase from Manitoba of power in amounts up to 200 MW, and with expiry in 1982. Delivery of this power, and other aspects of interconnected operation are governed by an Interconnection Agreement. The agreement provides for emergency and economy transfers, co-ordinated maintenance, and co-ordinated development.

9.10 Interconnections with Michigan and New York

The interconnections with Michigan and New York are shown in Figure 9-4.

Operation of all interconnections is governed by legal agreements between Ontario Hydro and the co-operating United States utilities. The interconnections with the Michigan Utiliites are governed by an Interconnection Agreement with Detroit Edison and Consumers Power. This Agreement makes provision for sharing of reserves, emergency and economy transfers, seasonal diversity transfers, co-ordinated maintenance, and the possiblity of co-ordinated development.

The Interconnection Agreement with Niagara Mohawk makes provision for sharing of reserves, emergency and economy transfers, and co-ordinated maintenance. The Memorandum of Understanding with PASNY makes provision for emergency transfers, co-ordinated maintenance, and the exchange of water for electricity. Niagara Mohawk and PASNY operate jointly with other utilities as members of the New York Power Pool.

Our relations with Niagara Mohawk and PASNY are also influenced by our common membership in the Northeast Power Coordinating Council (NPCC), a voluntary organization of all major utilities in Ontario, New York, New England and New Brunswick. NPCC provides a forum for discussion on common policies for reliability in design and operation of the interconnected power systems.

Straight numerical addition of the capacities of the interconnections listed in Figure 9-4 would indicate an aggregate capacity of 2855 MW for transfers with Michigan and 1750 MW for transfers with New York. However, because the flows on the interconnections cannot be precisely controlled,

and because there are transmission limitations in Ontario and the United States, the range of export and import capabilities during the next few years is as follows:

Export from Ontario	1000 to 2500 MW
Import to Ontario	1500 to 3000 MW

A complicating feature of operation of the interconnections with Michigan and New York is the circulating power around Lakes Erie and Ontario. Circulating power was already mentioned in Section 9.9 as affecting the operation of the interconnections with Manitoba. Even with no net import or export there is usually a flow of power over the interconnections, with power leaving Ontario for New York and simultaneously returning to Ontario from Michigan, or vice versa. The flow of circulating power sometimes reaches 600 megawatts. A net export under these conditions will increase the flow out of Ontario to New York and decrease or possibly reverse the flow into Ontario from Michigan, or vice versa. Circulating power therefore necessitates considerably larger capacity on individual tie lines than wculd be the case if precise control of all ties were possible, but it does have the advantage that it reduces total transmission losses.

A measure of control of circulating power is possible by twc techniques, both of which are costly and result in an increase in total transmission losses:

- phase-shifting transformers can be installed in the interconnections, as has been done at St. Lawrence, Windsor and Whiteshell, Manitoba.

- High Voltage Direct Current interconnections can be used. This method of control has not been adopted by Ontario Hydro.

9.11 Planning New Interconnections

Just as planning for expansion of the main Ontario Hydro system to meet growing loads is an ongoing process, so also is planning for expansion of interconnections to meet the changing requirements of growing systems. The planning of interconnections is more complicated administratively than planning a utility's own system, because a co-operative effort is necessary, work must be co-ordinated between groups working in different locations, and travel is necessary for periodic meetings.

Discussions are going on with Hydro Quebec to determine whether a new contract can be made to extend firm purchases beyond May 31, 1977. At present it appears that Hydro Quebec may not have

surplus firm power available for sale until their James Bay development is in production, but may have energy for sale prior to that time.

Because the mainly hydro-electric system in Quebec and the mainly thermal system in Ontario are complementary, there is much scope for emergency and economy transfers between the two systems even if firm power is not available. Therefore, a major planning study has been initiated between Quebec and Ontario to consider the possibility of additional interchanges.

Among the alternatives to be considered is a HVDC link, similar to that existing between Quebec and New Brunswick but having a larger capacity. Such a link would provide most of the benefits of normal interconnected operation and would avoid the problem of instability inherent in an ac interconnection between Ontario Hydro and Hydro Quebec.

Studies are going on regarding possible additional power transfers between Manitoba and Ontario in future years. Ontario Hydro is also studying the possibility of augmenting the existing interconnection between the East System and the West System.

The addition of new terminal facilities to permit use of HM3 circuit as a second interconnection with PASNY at St. Lawrence has been authorized, and preliminary studies are underway to consider an additional interconnection at Niagara.

9.12 National/Provincial Grid

As described in previous sections, Ontario Hydro has interconnections with the neighbouring provinces of Quebec and Manitoba. Likewise interconnections have been developed between Manitoba and Saskatchewan, between Alberta and British Columbia and between Quebec and New Brunswick and Nova Scotia. All these interconnections developed from the requirements of adjacent provinces, rather than from considerations of Canada as a whole.

A major study was carried out in the 1960's by a Federal Provincial Ministerial Committee to consider a high capacity transmission grid interconnecting all provinces of Canada. The recommendations of that Committee, given in their report of July 1967 were that further studies of the national network should be deferred for the time being, but that consideration should be given to strengthening regional ties. Those recommendations were in line with Ontario Hydro's views, and the interconnections between Ontario and Manitoba and Quebec have been strengthened since 1967.

Proposals for further study of a National Grid, or at least of major interprovincial grids in eastern and western Canada, have been raised several times since 1967. In 1973 a proposal was made for an Eastern Canada Grid, as a means of facilitiating development of nuclear power in Nova Scotia and hydro power in Labrador. The National Grid was raised again in January 1974 at the First Ministers' meeting on energy, and the Federal Government offered to assist financially in studies. In early 1975 the Interprovincial Advisory Council on Energy (IPACE) initiated a study of a National Grid. This study is at the stage of finalizing its terms of reference.

In addition to the proposed IPACE studies there are two major studies of regional grids now underway:

1. Quebec, Nova Scotia, New Brunswick, Prince Edward Island and Newfoundland are considering a regional grid.

2. Quebec and Ontario have started a major study of increased interconnection capacity between Quebec and Ontario.

10.0 FINANCIAL AND ECONOMIC CONSIDERATIONS

Contents

Appendices (Bound in Volume 2)

10.0 FINANCIAL AND ECONOMIC CONSIDERATIONS

10.1 Summary

This section summarizes the process of selecting the best alternative from the financial and economic viewpoint, and contrasts this with the process of cost allocation, i.e., of establishing the cost of power. It also discusses the subject of general resource availability and capital limitations.

10.2 Selection of the Best Alternative

A. General Discussion

In the financial and economic areas, Ontario Hydro's long range planning is concerned with its internal economic efficiency, its impact on the external economy, and its ability to finance expansion.

The objectives governing financial and economic concerns are included in the decision process by means of:

- restrictions (also referred to as constraints);
- rankings of alternatives based on differences among them; and,
- trade-offs with other objectives.

Generally speaking, restrictions put absolute limits on the degree to which economic efficiency objectives may be pursued at the expense of other concerns such as safety and appearance. They may be imposed internally (for instance, design standards) or externally (for instance, government environment-related regulations).

In view of expected difficulties in financing system expansion, a restriction has been placed on alternatives having high capital cost. This restriction may prevent economic efficiency from being as high as could be achieved if high capital cost alternatives could be implemented.

The ranking of alternatives in terms of differences in internal economic efficiency is done by the discounted cash flow cost comparison described under item B. Rankings with respect to differences in impact on society are obtained by analysis of social costs and benefits as described in Section 10.3. Rankings with respect to financial objectives are not required since, apart from the capital restriction mentioned above, financial objectives are achieved by actions which are independent of the selection of specific alternatives. That

is to say, provided the alternatives meet the capital restriction, such measures as system expansion charge adjustments and rate smoothing will achieve financial objectives regardless of the alternative selected.

Alternatives may not show the same ranking for economic efficiency as for their effect on other areas of concern. In such cases, selection of the best alternative is accomplished by trading off the advantages of one alternative in one area against the advantages of another alternative in a different area, taking account of the relative importance of the areas.

While economic differences can be quantified, many other differences cannot. As a result the trade-off process requires considerable judgement. Control of this judgement is obtained by corporate and public review of proposals before major alternatives are committed for design and construction.

B. Internal Economic Efficiency

Internal economic efficiency, for the purpose of this report, is defined as the value of the physical output of a process divided by the net cost of resource inputs to that process. Generation and bulk transmission alternatives are designed to supply the same electric output for Ontario's primary electric load. Therefore, differences in their economic efficiency are determined by differences in the net cost of resource inputs. The net cost is the gross cost minus any receipts from the sale of by-products.

Cost comparisons are used to determine differences in the net cost of resource inputs. For these comparisons, estimates are made of the amount and timing of payments by Ontario Hydro for the acquisition of all the resources required to carry out each alternative. Differences in the pattern of the year-by-year payments are accounted for in the comparison by discounting the payments to a common point in time, using a discount rate appropriate to the corporation as a whole.

The estimated payments have the following characteristics:

(a) They represent what is considered most likely to occur. An allowance is therefore included for the estimated escalation of wages and prices. The possibility of error is recognized and may be included in the comparison by sensitivity analysis. (See Appendix 10-A Item M).

(b) They include only costs that can be influenced by the decision. Past (sunk) costs and common costs are therefore not included.

(c) They are costs to Ontario Hydro for the acquisition of all resources from the economy. Expected allocations of these costs to the cost of power and internal charges are not included. Interest payments associated with borrowed funds are also not included. The cost of borrowing is an indicator of the time-related value of resources and is therefore taken into account through the discounting process. In order to avoid unnecessary decision-making effort (and hence cost), simplifications and approximations are used whenever this can be done without invalidating the comparison.

C. Specific Factors

Appendix 10-A discusses the methods of handling the following factors in economic efficiency comparisons:

- Discount Rate
- Life Expectancy
- Escalation and Inflation
- Interim Replacements
- Insurance
- Taxes
- Operations and Maintenance Costs
- Inventories
- Commissioning Costs and Energy Credits
- Overheads
- Equivalent Uniform Annual Costs (EUAC)
- Sale of By-Products
- Risk (Sensitivity Analysis)
- Heavy Water Costs

D. Economic Efficiency and Cost Allocation

Factors used to estimate internal economic efficiency are generally different from those used for cost allocation, i.e., for establishing the cost of power. The objectives and the

factors taken into account in cost allocation, as compared to internal economic efficiency, are described in Appendix 10-B.

10.3 Social Costs and Benefits

A. General Discussion

An organization's activities may impose costs and confer benefits upon society at large, over and above the costs and benefits normally identified in the organization's accounting statements. The efficient allocation of resources and the best practical level consumer welfare requires that total costs and benefits enter into the economic evaluation procedure.

The most efficient level for any particular type of productive activity can be defined as that level of production where incremental social costs exactly equal incremental social benefits. The social welfare function, which determines the point at which incremental social costs and benefits will be equal, will depend upon the values and insights which society places upon such factors as economic growth, equality of income distribution, quality of life, etc.

B. Defining Social Cost

Social costs are all the costs resulting from a productive activity which are borne by society as a whole. Thus, they consist of the direct costs of resources utilized in the activity, together with the value of any loss in welfare, or increase in costs, which that activity causes to any other individual or entity in the economy.

For instance, the social costs of generating electricity from fossil fuels are the costs incurred directly by the utility plus the extent that losses in welfare or additional costs are imposed upon society (e.g., through increased air pollution building deterioration may accelerate, or building maintenance costs may increase).

C. Defining Social Benefits

Social benefits are all of the gains in welfare which flow from a particular activity, whether or not they accrue to the individual or institution undertaking the activity. They comprise the total improvement in welfare of the society as a whole, including the group undertaking the activity.

For instance, Ontario Hydro receives benefits in the form of revenues from the sale of electricity. However, total social

benefits will exceed these benefits to the extent that electricity provides a needed form of energy to individuals and industry, to the extent that industry and technology are stimulated in the provincial economy, and to the extent that income and employment are increased as the result.

D. External Costs and Benefits

Externalities associated with Ontario Hydro are those costs and benefits experienced by society which are not internalized within Ontario Hydro's financial statements or operating calculations. They include the effects on the environment, effects upon the rate of technological innovation, and multiplier effects upon the economy, etc.

E. Opportunity for Quantification of Externalities

To a great extent, external costs and benefits associated with the operations of Ontario Hydro are incapable of quantification and, therefore, difficult to include in any decision-making evaluation. For example, external costs associated with aesthetics are largely intangible, evaluation of the losses in welfare as a result of increased pollution is to a large extent subjective, the impacts upon standards of animal and human health may be greater in the long run than the short run, etc. The exact nature of the benefits conferred upon society as a result of income, employment and technological multipliers and the quality of life in general are equally difficult to evaluate. However, wherever possible, such factors should be included in the decision-making procedure, albeit implicitly in qualitative analyses.

10.4 Escalation and Inflation

Ontario Hydro's forecast of future escalation and inflation is summarized in its "Economic Forecasting Series." The methodology used to produce this series has been developed by an evolutionary process. Forecasts produced before 1972 generally predicted varying escalation rates for three to four years, followed by the long-term trend of the historic series. As escalation intensified during the 1973-74 period, more effort was made to forecast the future. With the economic forecasting systems now in use and under development, Ontario Hydro should be in a better position to estimate projected future costs.

The Economic Forecasting Series is developed and produced in the following steps, which are discussed in Appendix 10-C:

- Data Collection and Mathematical Manipulation

- Data Interpretation into Future Economic Assumptions
- Interpretation of the Assumptions and Data into Specific Index Forecasts
- Production of Fuel Forecasts
- Publications and Distributions

It should be noted that the methodology described in Appendix 10-C is an iterative process. It is established to produce an end result in a form desired by various users, and this form is continuously changing. Between successive forecasts, internal and external contacts are made and interpretations of events relative to their specific areas are received. Meetings are held from time to time with major users, to discuss the data, format and the forecasting techniques.

In general, the variability of any forecast increases as one is trying to forecast further ahead in time. Compounding this situation are the frequently abrupt and often unpredictable decisions and events encountered in today's economy. This can have a much more significant effect on cost and price forecasts in the short run than errors in predictions of longer term trends.

In decisions on long range planning, the correctness of relativities between projected future costs and prices are more important than are the absolute figures shown for the individual categories.

10.5 Interest Rate Forecast

A. Methodology

Ontario Hydro prepares an interest rate forecast quarterly. The interest rate forecast details the expected cost of the funds to be borrowed by Ontario Hydro in the Canadian, United States and other capital markets. The forecast is based on an assessment of expected capital market conditions over the period given Ontario Hydro's capital requirements. The factors considered in the preparation of the forecast include the following:

- the business cycle phase in Canada
- levels of Canadian unemployment and inflation
- Canadian monetary and fiscal policy
- potential needs of other Canadian borrowers

- savings patterns in Canada: structural changes
- government regulations affecting interest rates or flows of funds
- factors similar to the above for the United States economy
- Central Bank views and regulations concerning foreign borrowings
- foreign exhange holdings in Canada and major lending countries
- availability of foreign markets, including interest rate levels and currency levels.

The resulting forecast of general interest rates is adjusted to produce the forecast of Ontario Hydro's borrowing cost. These adjustments take account of the particular characteristics of Ontario Hydro's debt issues such as the flexibility in timing, the mix of long and intermediate term bonds, and the use of international bond markets.

B. <u>Variability of Interest Rate Forecasts</u>

Interest rates are determined by the interrelationships between many diverse factors, and forecasts must be developed with all of these in mind. Political, economic and social factors can change suddenly and these changing conditions can necessitate revisions in the forecast. Also, generally the longer the period under consideration the greater will be the chance of variation of the forecast from actual. While it is possible that interest rate forecasts can be accurate for the first year to within plus or minus 1/2 to 1%, beyond that period the potential variation could be wider and extremely difficult to quantify.

10.6 General Economic Perspective

A. <u>General Resource Availability</u>

Resource price levels are increasing generally, and traditional price relationships are experiencing realignment.

In the energy sector, supplies and prices are particularly uncertain. In addition, environmental constraints are influencing market shares and prices, and the effect of government efforts to encourage conservation in the use of energy is unknown.

Any planning procedure for the electric supply system must take into account the uncertainties of these changing relationships and anticipated structural developments. Energy problems cannot be resolved in isolation from the overriding economic issues involving economic growth rates, industrial development strategy, and public sector financing and fiscal policies.

The planning process for the province of Ontario must consider both the short and long term implications of placing differing emphasis upon alternative primary energy sources as these relate to such factors as:

- the maintenance of adequate supplies of resources;
- the safeguarding of national security interests;
- the encouragement of energy resource development;
- the export of surplus energy supplies under beneficial conditions;
- the acquisition of non-Canadian source energy supplies under favourable economic circumstances; and
- an alignment of energy policy objectives with other national goals such as those relating to Canadian ownership and protection of the natural environment.

B. Optimal Resource Usage

In theory, for optimum resource usage, the allocation of various primary energy inputs between alternative uses should be pursued to the point where substitution between inputs would diminish the aggregate welfare of Ontario residents. However, in practice this is not possible to achieve because of the many uncertainties in the various energy resources.

Ontario's demand for electricity absorbs an important share of the total primary energy input to the Ontario economy. The two critical determinants of this situation are availability and price. A deterioration in either of these dimensions could lead to:

- a change in the lifestyle in the province; or
- a deterioration of Ontario's competitive position with a consequent reduction in incomes and employment.

The optimum selection of primary energy input for electricity generation purposes cannot be based solely on the costs of

alternative methods of generation. It must also consider practical limitations such as:

- lead times and technical factors;
- security of primary energy supply; and
- uncertainties associated with forecasting future fuel prices.

C. Economic Impacts

If the province of Ontario is regarded as the decision centre, then the selection of alternative system expansion schemes is capable of causing significant impacts upon the economy, as measured by such economic variables as Gross Provincial Product, Consumer Prices and Employment. Decisions regarding the level and nature of capital expenditures will therefore reverberate throughout the economy as a result of direct effects and indirect and induced multiplier impacts. Other things being equal, a growth in capital expenditures can be expected to result in a relatively greater impact upon provincial incomes and employment as a result of these factors. Actual final impacts, especially upon prices, will depend to a large extent upon the degree of excess capacity in the economy at any particular time and the extent to which capital expenditures are made outside of Canada and Ontario. The latter also possesses implications for the foreign exchange rate and, therefore, the competitive position of Canadian industry.

10.7 Capital Limitations

A. Relationship of Financing Requirements to Selection of the Best Alternative

When alternative system expansion plans are being compared considerable emphasis is given to differences in overall economic cost (section 10.2). If expected financing difficulties mitigate against selection of alternatives with high capital costs a suitable constraint is imposed as a means of reducing the emphasis on overall cost.

B. Financing Costs

The process of arriving at financing costs begins with the recording of payments for resource acquisition in Ontario Hydro's books. To these amounts, an allocation of interest expense is added ("interest during construction"), and the total amount is capitalized at the time the plant is

commissioned. For each planning year, total capital requirements are estimated, and decisions are made on the amount of financing to be carried out through the sale of bonds (which results in interest expense), and the amount to be financed through system expansion charges.

If necessary, it is proposed that system expansion charges be made each year in order to preserve Ontario Hydro's financial integrity and hence enable it to obtain bonds at favourable interest rates. These charges to the customer are arrived at by starting from a desired yearly return on equity, and deducting from this amount the debt retirement charges for that year.

C. <u>Capital Constraints as a Factor in the Selection of the Best Alternative</u>

Because of a scarcity in funds available for borrowing, it is foreseen that Ontario Hydro will not be able to take advantage of all the cost reduction opportunities available to it through the use of capital.

Methods of best utilizing available capital are under active consideration.

11.0 THE DECISION PROCESS AND PUBLIC PARTICIPATION

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11.0 THE DECISION PROCESS AND PUBLIC PARTICIPATION

A. Summary

This Section briefly outlines the evolution of the public participation process in Ontario Hydro and notes some of the new policies and procedures which have been developed in response to concerns and suggestions of the public. Some of the concerns Ontario Hydro has with respect to the present public participation and approval procedures are presented. A revised approach is proposed for some of Hydro's major projects.

B. Background

Up to 1970 major plans were developed and line routes and stations sites selected by Ontario Hydro on the basis of internal studies and limited consultations with Provincial Government Ministries and those municipalities in which the facilities were to be located. Although these studies included detailed analyses of cost, technical, safety and socio-economic considerations, they were in large part Ontario Hydro staff interpretations of society's goals as they applied to electric power facilities.

By 1970 Ontario Hydro had selected a route for its 500 kV lines from Middleport TS to Cherrywood TS using this process. However, by 1972 vigorous public opposition to the proposed route resulted in the Provincial Government appointing the Solandt Commission to inquire into the matter and make recommendations thereon.

After a series of public hearings held by the Solandt Commission in August and September 1972, Ontario Hydro made a final summation statement to the Solandt Commission dated October 16, 1972 which included the following:

> "Ontario Hydro recognizes that public participation is highly desirable and we have begun to apply this principle to the planning process for recent transmission projects, such as the right of way for the transmission line between the Lennox Generating Station and Wesleyville."

The summation went on to outline the broad phases of a public participation procedure which was being implemented on major projects then underway. These proposed public participation procedures were endorsed by the Solandt Commission in its Interim Report dated October 31, 1972.

Subsequently, Ontario Hydro developed more detailed procedures as a general guideline for public involvement, to be followed by its project management staff when developing plans for the selection of transmission line routes and generating and

transformer station sites. These procedures were published in an Ontario Hydro document dated January 15, 1974.

Some of the steps foreseen in these procedures have been superseded by changes in legislation. However, the basic concepts remain the same. Based on practical experience and suggestions made by the public for improving the process, more comprehensive procedures are now necessary.

C. Ontario Hydro Activities

In the last four or five years, the Corporation has developed new policies and procedures and improved existing ones in response to concerns and suggestions of the public.

Some of the policy actions are:

(a) Improved land compensation policies. (See Appendix 8-B)

(b) Developed more effective procedures for environmental analysis (see Sections 8.5 and 12.0).

(c) Directed increased attention to the design of facilities which reduce adverse environmental effects. This resulted in changes such as:

- the use of SF6 switchgear to reduce station size, where applicable,
- the use of remedial landscaping, and
- the use of selective clearing of line right of ways.

(d) Improved construction and maintenance procedures to reduce environmental damage. (See Appendix 8-A)

(e) Initiated studies of the effects of transmission lines on agricultural operations by the Ridgetown College of Agriculture Technology.

Some of the procedural improvements arrived at to provide a more satisfactory degree of public involvement in the planning process include:

(f) Designed a process for involving the general public in the initial planning phases of projects; working with public representatives, and other community leaders.

(g) Arranged planning seminars at which representatives of provincial government ministries and interest groups could review with Hydro their concerns and contribute useful

ideas for new procedures being developed by Hydro for use in up-coming projects.

(h) Established direct liaison with several involved government ministries.

(i) Conducted public attitude surveys to gauge the public's reaction to Ontario Hydro facilities.

In addition Ontario Hydro staff have met many times with public groups relative to ongoing projects and issued background information for the purpose of achieving a greater degree of mutual understanding on the part of Ontario Hydro and the public regarding the concerns of the public and the problems which face Ontario Hydro.

D. Government Bodies Which Review Ontario Hydro Plans

In addition to the Royal Commission on Electric Power Planning, two other bodies have been given authority by legislation to investigate and hold public hearings on major Ontario Hydro projects.

In 1973, the Ontario Legislature revised the Ontario Energy Board Act to require Ontario Hydro to submit proposed changes in rates or charges to the Minister of Energy who in turn refers the proposal to the Ontario Energy Board. The Act also gives the Minister the power to refer to the Board:

> "any matter in any way affecting or related to rates or charges by Ontario Hydro to its customers including, without limiting the generality of the foregoing, principles and practices respecting power costing, ratemaking, financing, service reliability, system expansion and operations."

The Board is required to hold a public hearing to investigate and examine matters referred to it and report thereon to the Minister.

The Environmental Assessment Act was passed by the Legislature in 1975. The regulations for the Act are being drafted at the time of this writing. The Act applies to major generating and transformer stations and transmission line projects of Ontario Hydro. The Act requires that Ontario Hydro submit to the Minister of the Environment an environmental assessment for projects falling under the Act and receive the Minister's approval before proceeding with the project.

E. Planning with Public Participation - Experiences with Early Projects

Ontario Hydro is firmly committed to public participation and recognizes the public's contribution to the planning of its projects in recent years. Valuable information and suggestions have been provided, particularly on local environmental problems by local individuals and groups. It is evident that local public interest groups are in a position to help project planners to apply provincially-developed guidelines for establishing land use and other priorities.

Nevertheless Ontario Hydro's experiences in the last four to five years have revealed that effective open planning is complex and difficult to achieve when applied to the expansion of electric utility facilities. The major concerns are:

(a) Lead times from the initiation of planning to the date on which a facility is placed in-service have been increased by two to four years for major projects. The lead time for the approval and construction of a generating station on a new site is now 12 to 13 1/2 years, and for approval and construction of a 500 kV transmission line about 8 years. The planning, public participation and approval process has so lengthened lead times that many facilities will be late coming into service.

Eventually Ontario Hydro may be able to extend its schedules for new facilities to include adequate time for public participation. Increased lead times are undesirable because they increase the possibility of forecasting errors and make it more difficult to respond to changing conditions. In some respects increased lead times can be self-defeating because it is difficult for people to perceive and accept the urgent need for decisions on facilities which will not come into use for many years.

(b) There is a wide diversity of public opinion about most major electric projects and it is extremely difficult to obtain public consensus.

The difficulty of obtaining a consensus arises in part because the main issues are not clear cut and because of the considerable time required to provide adequate information on these issues.

(c) The large potential geographical area in which proposed electric facilities could be located means that in the early planning phases, the potential public that could be affected is large. This makes it impractical to have personal contact with the general public in the early planning phases. As a result many people do not become

aware of the proposed facilities until quite late in the process when options are limited if the facilities are to be placed in-service on time.

(d) Only a relatively small section of the general public has shown an interest in Hydro projects and with some exceptions, municipal and regional governments have not taken an active and constructive role in the public participation process.

(e) There has been no clearly defined process for obtaining government approvals for electric projects.

F. <u>Two-Stage Approvals and Public Participation Concepts</u>

The problems encountered are part of society's larger problem of deciding where it wants to go and how it should get there. Careful consideration must be given to the options available for public involvement, and the direction in which that aspect of utility planning should move in the future for greatest effectiveness and acceptance of the end proposal. The formal review and approval process should provide an opportunity for meaningful public input and incorporate the requirements of the Environmental Assessment Act.

The following approach is suggested as one possible way of improving the process. It has been used to form the basic plan for public involvement in studies for future generating and transformer station sites and transmission routes.

The decision-making process would parallel the public involvement process in two separate stages. In the first stage, the scope of the study is very broad. It considers provincial impacts and applies these along with major regional constraints. This is to establish the scale of a study area at a manageable size for detailed study in the second stage. Reducing the scale is essential if the general public and local communities are to participate in a meaningful way during the second stage.

Alternative plans would be examined and the need for one of them approved during the first stage.

The second stage would define and study alternative locations within the study area and recommend one or more of them for government review and approval.

In each stage the public would be involved as part of the study development. The views of government ministry staffs, municipalities, and a cross-section of organizations and individuals would be sought. These views would then be

considered through a wide variety of forums. The priorities, concerns and values of these diverse publics would then be presented in the recommendation submitted for formal consideration by Government.

All elements of the public should have an opportunity to appear before a review board, so that individual interests may be represented.

(a) <u>The First Stage</u>

The study would begin by examining the requirement for additional facilities and alternative plans to meet that requirement. For example, this examination and review might establish that one or more transmission lines are required from a generating station to an existing or new terminal station near a major load centre, or that a new generating station site is required within a defined area on one of the Great Lakes. At this stage, certain technical matters would be discussed and decided on, such as:

- the voltage levels for transmission lines;
- the use of single circuit or multi-circuit lines;
- the ultimate number of lines to be provided for on a right-of-way;
- the ultimate station capacity to be provided for on generation and transformer station sites.

This stage will also define the geographical areas which should be studied in detail, based on the general location of the generating station and the terminal transformer stations. This would include the identification, through environmental studies, of those parts of the study area which are less suitable for locating generating stations and transmission corridors and establishing a basis for evaluating alternatives. A basic goal is to reduce the number of alternatives for further study.

In this preliminary stage, to accomplish the above-mentioned work, the scale of the issues for discussion and resolution suggests that Hydro, in addition to the required liaison with regulatory agencies, should seek primary assistance from Provincial Government Ministries, Regional Governments and their staffs and other organizations and groups having provincial or regional interests. Local authorities and interest groups or individuals would be less likely to seek involvement at this stage, although contributions from any such sources on these topics would always be welcome.

Decisions made in this early stage must be based on broad considerations of provincial priorities for land use and environmental effects which can be defined on a broad scale. At this stage, the decisions cannot and should not include detailed analysis of local effects on small areas. Appropriate steps can be taken in the second stage to avoid sensitive locations which are a small part of the study area.

(b) The Second Stage

The study will concentrate next on geographic areas approved in the first stage. Since the environmental studies conducted in the second stage are more intensive, most of the emphasis on public involvement is now expected to shift to the local level, with increasing participation in the planning by local groups and individuals. These should include the municipalities and representatives of the local branches of province-wide organizations and government ministries involved in the first phase.

This stage should deal primarily with the specific location of the generating station site, transformer station site and transmission line route. The beneficial and adverse impacts on the community, procedures used in acquiring property, and where applicable, the methods employed in building and operating the facility should be fully examined and reviewed in public.

G. Establishing a Sound Working Forum

In order to enable the many interests represented by organizations and the different government levels to have opportunities to study and contribute ideas to project plans, specific forums such as seminars and workshops should be an integral part of each study plan. To help determine local priorities on such concerns as land use, cross-sectional working groups can be very effective, particularly if the members of these groups undertake a responsibility to maintain communication channels with the members of their organizations. Experience to date shows this to be promising.

Underlying the whole principle of program planning which effectively involves the public is the assumption that during the entire process, in addition to the planned involvement of groups, organizations and individuals, the public at large is kept informed of the project's goals and its progress at the various stages.

News media should play an important part in this process, both by providing information and comment on the various activities of the project, and in stimulating public understanding of the

many complex and technical areas of utility planning. In practice, media activity increases when a given project or activity generates local news.

Other avenues through which the public can learn of project developments are drop-in centres and sponsored public meetings, and direct mail.

The informal process for public participation as outlined here can provide for a good two-way flow of information between Hydro, people at the official level, and the residents of affected communities.

However, there is little doubt that no matter how effectively the public helps Ontario Hydro develop planning solutions to its route and site location requirements, certain of the many interests at stake, whether individuals or groups, will not be satisfied with the final proposal. For these people, a formal hearing process under the auspices of a body appointed by the Government, at which differing viewpoints on major issues may be most effectively debated, is an equitable means of reviewing the relative merits of Hydro's recommendations.

It is clear that public participation in planning is still evolving and requires different treatment for different projects and different locations. It is also clear that considerable experimentation may be necessary before a fruitful decision-making process is available to complement the planning function.

12.0 ALTERNATIVE SYSTEMS

CONTENTS

APPENDICES (Bound in Volume 2)

12.0 ALTERNATIVE SYSTEMS

12.1 Summary

In this Section a number of alternative future system arrangements are considered, in order to provide a basis for making decisions which are required in the near future on new transmission and generation projects.

12.2 General

If the power system is to be expanded in an orderly and economic manner and with acceptable environmental and social effects, transmission and generation facilities required in the near term must fit into future system requirements. Therefore, in order to provide a basis for decisions on the near-term transmission requirements and generation locations, a number of alternative conceptual system arrangements for the power system by about 1995 are considered in this Section. The planning-horizon of about 20 years has been chosen as a compromise. It is about as far as one can predict the nature of the future system with sufficient confidence to use the prediction as a basis for present-day decisions and expenditures. Beyond that time, changes in generation and transmission technology, in the structure of society, or in the life style could result in major changes in the design of the electric power system. On the other hand, the long lead time required for the installation of facilities means that decisions must be made today for transmission facilities required in the early 1980's and for generation facilities required in the mid-1980's. Therefore, the minimum possible planning horizon is the mid-1980's, and 20 years is only a 10 year projection beyond this minimum planning horizon.

It is also important to emphasize that today's conceptual design of a system 20 years in the future cannot be considered as fixed. The most desirable system concept for about 1995, will continually change year by year in the future as new information becomes available. Today's conceptual design can only be considered as being a guide for planning and making the decisions which must be made now.

12.3 Process

The systems compared in this Section have been developed to supply the forecast demand for power in accordance with certain criteria for adequate reliability. The criteria are outlined in Section 12.5. The purpose of these criteria is to ensure that the comparison of alternative systems is made on a common basis. The criteria which will eventually be used for the

detailed design of the 1995 system may be different, but it is unlikely that the differences will be significant enough that were they known now, they would affect the choice between systems in this comparison.

The alternative systems which have been compared are discussed in Sections 12.7, 12.8, and 12.9.

12.4 Possible Future East System Generation Programs

A. 1995 Loads

The alternative system expansion programs compared in this report are based on one of three load forecasts:

(a) The 1975 forecast of most probable loads. This was based on specific varying annual load growths from 1975 to 1984, and a constant annual load growth of 7.1% thereafter.

(b) An illustrative lower forecast, in which annual load growths from 1975 to 1982 successively decline, reaching a value of 4% in 1982, and remain at 4% thereafter.

(c) An illustrative higher forecast, in which annual load growths from 1975 to 1982 successively increase, reaching a value of 10% in 1982, and remain at 10% thereafter.

The 20-minute primary peak loads in megawatts under each of these forecasts are as follows:

Year	Illustrative Lower 1975 Forecast	1975 Forecast of Most Probable Loads	Illustrative Higher 1975 Forecast
1980	19980	20598	21937
1985	24425	28809	35169
1990	29717	40595	56640
1995	36156	57203	91220

The expected geographic distribution of load is shown in Figure 12-1.

B. Generation Expansion Programs

In September 1975, as a result of direction by the Treasurer of Ontario, Ontario Hydro reduced its earlier proposed generation expansion program and adopted a new proposed program known as Program LRF43P. From 1978 onward, the reliability of this program in meeting the 1975 forecast of most probable loads was

substantially less than Ontario Hydro's recommended level for the Loss of Load Probability of 1 in 2400.

Program LRF43P generally conformed with the conclusions noted in Section 6.1. That is:

(a) It was based on the installation of CANDU nuclear stations ultimately to provide all the base load generation except that provided by hydroelectric capacity.

(b) It made no major commitments to the use of oil and gas, beyond that required by the first four 547 MW oil-fuelled units at Lennox GS, the first four 547 MW oil-fuelled units at Wesleyville GS, the gas/coal units at Hearn GS, and the relatively small gas turbine installations.

(c) It presumed the requirements for new generation beyond that provided by the CANDU units would be met by coal-fuelled stations.

The generation proposed in this program is shown in Figure 12-2. By 1995, it provides a Loss of Load Probability of about 2.8 in 2400 (about 3 days in 10 years). It has less generation than that used under the 7% load growth case shown in Figure 2 of Reference 2.0(1).

In the period up to 1995, further hydroelectric generation and energy storage schemes may be developed. These were not included in Program LRF43P because they are unlikely to form a large part of the total capacity and because their nature, cost advantage, and location are currently unknown.

Program LRF43P assumed that no firm power purchases from or sales to Canadian provinces or the United States will be available in the 1990's. It also took no account of the installation of small combined-use stations (refuse-burning or fossil-fuel burning stations providing electricity and district or process heating). Some of these are likely to be installed, but it is unlikely that they will substantially reduce the requirement for generation in large central electric generating stations.

For the same reasons as concluded in Section 6.1 S, concerning the economic advantage from installing larger units, Program LRF43P was based on the assumption that the new thermal-electric units will be increased in size progressively from 500, to 750, to 850, to 1200, and to 2000 MW CANDU units, and from 500 to 750 MW fossil-fuelled units. It presumed specific years for first introduction of the larger sizes into the operating system. These years were chosen arbitrarily. Future studies along the lines outlined in Section 6.1 S will have to be done to determine the actual timing and sizes of the larger units; and these studies will reflect the load forecasts and all other pertinent factors at the time each decision is taken to install the next larger size of units. Nonetheless, it is judged that LRF43P is a reasonable reference program for

current comparisons of alternative schemes for the future generation and bulk transmission schemes which meet the requirements for supplying the electric load in 1995.

In February 1976, the Chairman of Ontario Hydro, responding to the direction of the Provincial Treasurer, announced a further reduction in Ontario Hydro's proposed system expansion program LRF43P up to 1985 and beyond. The announcement came at a time when the work of developing the systems outlined in this section had been largely completed. This reduced program may necessitate restrictions on load growth below the growth level assumed in LRF43P. For example, restricting the load growth to 6% has been suggested as one possibility.

Figure 12-3 compares the future load projections for four alternative load growths. It shows that, provided load growth continues, the value of 57203 MW, forecast for 1995 by the 1975 forecast of most probable loads, will eventually be reached:

In 2007, with the illustrative low forecast;
In 1999, with the 6% growth after 1975; and
In 1990, with the illustrative high forecast.

What the future load growth will be is unknown. However, it is necessary to compare possible alternatives for future development in order to reach decisions on the next steps in generation and transmission development. For this purpose, this report uses the 1975 most probable forecast and Program LRF43P as a reference program, albeit recognizing that:

- current capital limitations which led to the adoption of LRF43P in September 1975, and to further reductions in the program in February 1976, may or may not continue or intensify in future years. If they intensify, they may require limitations in load growth, and/or replacement of proposed nuclear units with fossil-fuelled units.

- higher load growths may result in earlier development, and lower load growths result in later development of the system. In addition, they may result in modifications to the nature of the generation expansion program.

In this report, the system generation expansion programs corresponding to the illustrative lower and higher load forecasts are devised to correspond to the main assumptions used in devising Program LRF43P. That is, they presume that base load will be supplied by CANDU nuclear capacity and existing hydroelectric capacity; that the remaining requirements for new generation beyond that provided by CANDU units will be met by coal-fuelled stations; and that the reliability of supply to load in 1995 will be about the same as that of LRF43P.

12.5 Criteria and Assumptions Used to Devise Alternative Bulk Power Schemes

The basic criteria used to test the adequacy of a proposed transmission system are described in Section 7.10. Other criteria and assumptions required to develop proposed systems are outlined in this subsection.

A. Generating Site Development

(a) The maximum amount of generation on one site in 1995 is assumed to be about 12,000 MW. It is desirable to limit the generation actually installed on one site to an amount such that if it were all forced out of service, the load could continue to be supplied provided all other generation were available. That is, the amount should not be larger than the total system generation contingency reserve.

(b) Air quality guidelines limit the amount of fossil generation on one site to about 4,500 MW and the minimum distance between such installations to about 30 miles.

B. Transmission

(a) Additional bulk power transmission will consist mostly of overhead 500 kV 2-circuit lines (see Appendix 7A). Special cases in which 1-circuit 500 kV or 765 kV lines are used are indicated in the alternatives.

(b) Not more than two 2-circuit 500 kV lines or three 1-circuit lines will be located on one right of way except for special cases in congested areas (see Section 7.11).

(c) Ontario Hydro's existing bulk power system is primarily a 230 kV system. By 1995 it is expected that the bulk power system will comprise mainly 500 kV circuits. Existing and some new 230 kV circuits, while still an important part of the overall power system, will not, except in special cases, be operated as part of the bulk power system. This is because of the necessity to avoid excessive short circuits on the 230 kV facilities, because their capacity may limit the power transfer capability of the higher voltage circuits, and because they will be required for the supply of local load. The load in the areas will be supplied primarily at 230 kV from existing or new 500-230 kV transformer stations in these areas.

However, the possibility of reducing the amount of new transmission by using existing 230 kV transmission is discussed in Section 12.9.

(d) Provision will be made for the following approximate loadings on interconnections with other utilities in 1995:

i) 1,500 MW in the St. Lawrence area (with Hydro Quebec and New York State)

ii) 1,500 MW at Niagara (with New York State)

iii) 3,000 MW at Sarnia (with Michigan)

These loadings may be either into or out of Ontario, and the facilities in the part of the system adjacent to the interconnection are designed to accommodate these loadings with one circuit out of service. The total amount of import or export possible with these loadings cannot be determined directly from them. It depends on the amount and direction of circulating power conditions throughout the interconnected systems in Canada and the United States.

(e) The maximum wintertime capacity for short 500 kV circuits is 3,700 MW. Lines longer than 50 miles or so have a lower capacity depending on the ability of the system configuration to meet the design criteria (see Appendix 7-A).

C. Requirement for Separate Rights of Way

(a) Two rights of way separated for most of their length by at least 5 miles are required for egress from energy centres where the egress is longer than 15 to 20 miles (see Section 7.11).

(b) One right of way is acceptable for egress, regardless of length, from a site capable of accommodating not more than about 10% of total system peak load. Similarly, the loss of one of the two rights of way out of a generation site should not reduce the output of the site by more than that amount (see Section 7.11).

(c) After the permanent loss of all circuits on a right of way serving a major load area (more than 500 MW of load) or interconnecting major portions of the bulk power system, the remaining system must be capable of supplying 85% of the peak load in the affected deficient area assuming that the generation in the the affected area is operating at an output estimated to be available 98% of the time (see Section 7.11).

D. Load & Generation Balance

The basic criteria described in Section 7.0 call for the system to be tested at the most severe expected load and generation conditions. These conditions are specified to ensure a reasonable probability that the load can be supplied with the amounts of generation that may be available under severe contigencies. The conditions assumed for this study are described in detail in Appendix 12-A.

12.6 Possible Locations of New Generating Stations

As discussed in Section 6.5, study areas have been delineated on the shores of the Great Lakes, major rivers, and inland lakes which have potential for the location of future generating stations, (see Figure 6.5-6). The assumed number of sites in each area and the site capacity based on preliminary data are tabulated below:

Area	Projected Number of Sites in Area	Approximate Maximum Capacity For Nuclear = N Fossil = F MW	Projected Site Capacity MW
North Channel of Lake Huron	2	N - 12,000 F - 4,500	12,000
Eastern Lake Superior	2	N - 12,000 F - 4,500	12,000
Northern Georgian Bay	2	N - 3,000 F - 4,500	4,500
Lake Timiskaming	1	N - 2,000 F - 3,000	3,000
Lake Wanapitei	1	N - 2,000 F - 0	2,000
Lake Nipissing	1	N - 2,000 F - 3,000	3,000
Niagara River	1	N - 6,000 F - 0	6,000
Eastern Lake Erie (East of Long Point)	1	N - 12,000 F - 0	12,000
Western Lake Erie	2	N - 12,000 F - 4,500	12,000
Southern Lake Huron	1	N - 12,000 F - 4,500	12,000
Southern Georgian Bay	2	N - 12,000 F - 4,500	12,000
Ottawa River	2	N - 2,000 F - 3,000	3,000
St. Lawrence River	2	N - 12,000 F - 4,500	12,000
Eastern Lake Ontario (East of Wesleyville)	1	N - 12,000 F - 4,500	12,000
Wesleyville		N - 12,000 F - 4,500	12,000
Darlington		N - 12,000 F - 4,500	12,000
Lennox		N - 10,000 F - 4,500*	12,000*
Bruce		N - 12,000* F - 4,500	12,000*

* - including generation already installed

12.7 Alternative Systems Using Large Generating Units and Large Central Generating Stations and Based on Supplying the 1975 Forecast of Most Probable Load

A. General

Unless otherwise noted, the alternative systems compared in this Section are based on Generation Program LRF43P except that a 4500 MW fossil-fuelled station is used in place of one 3000 MW station and the 2-750 MW units at E25 as shown in Figure 12-2.

All alternatives discussed in this Section include certain 500 kV transmission lines which exist or for which routes have been approved. These are shown by the broken lines in Figure 12-5 and comprise lines on the following routes:

Bruce GS to Milton TS
Nanticoke GS to Oshawa TS
Lennox GS to Oshawa TS
Hanmer TS to Claireville TS

Starting from the common bases discussed above, each alternative system has been designed to conform to the criteria and assumptions and to show the effect of widely different geographic distributions of generation. These systems are shown in diagrammatic form and briefly described in Section 12.7 B.

In order to illustrate the concepts being considered, the diagrams show proposed new transformer and generating stations and transmission lines located in various areas. A detailed study will be required before any potential sites or line routes can be identified in any area, and these may be in different locations than the diagrams appear to show. Therefore, the diagrams are semi-geographic only, and are not intended to infer actual site or line locations.

The distribution of the generation with respect to load areas is summarized in Figure 12-4. The load areas are shown on the map in Figure 12-5.

For each of the alternative systems, subalternative configurations may be possible in various parts of the system without changing the main concept of the alternative. Typical subalternatives are shown in insets in the diagrams. They are not compared in this report, but they and possibly others will be compared in studies to be reported later.

In the part of the system west of London all alternative conceptual system arrangements show the same facilities. Alternative arrangements could have been shown for this part of the system. However, there are no near-term requirements for

major new facilities in this area and it is considered that alternative arrangements there would not have a significant bearing on the overall system concept. Therefore, in the interests of simplicity, alternatives for this area have not been shown.

The large number of alternatives precludes doing detailed studies at this time to discriminate between alternatives which are very similar in cost and environmental effects. For the same reason, there has been no attempt to study the timing required for the various system components. Requirements in earlier years could dictate some differences in the 1995 system. However, the systems have been developed on a consistent basis to meet the 1995 loads and it is considered that they are a reasonable basis for comparison of the various alternatives.

With minor exceptions each alternative system has the same total amount of generation and the same unit sizes. The location and type of all new generation (generating station E15 and later) is indicated on the diagrams.

This report provides approximate circuit mileages and route mileages for new transmission and routes for the alternative systems. The mileages are tabulated in Figure 12-6.

In a later report, a comparison of the alternatives presented in this report and perhaps additional alternatives will be made, including information on the environmental, cost and technical implications. Appendix 12-B outlines the approach proposed for use in the later report for identifying the environmental implications of alternative transmission systems.

B. Description of Alternatives

(a) Conceptual East System Arrangement for Mid - 1990's

Alternative 1A.

The generation is distributed throughout the system in amounts nearly proportional to the load. The additional generating station in southwestern Ontario is located on southern Lake Huron.

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	13,411	10,800	1.24
Niagara Hamilton	14,428	11,500	1.25
Central Ontario	26,221	21,300	1.23
Eastern Ontario	9,881	8,100	1.22
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1.26

LEGEND

EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY

ADDITIONAL 500 kV RIGHT OF WAY

ADDITIONAL 230 kV LINE

EXISTING GENERATING STATION SITE

EXISTING TRANSFORMER OR SWITCHING STATION

ADDITIONAL GENERATING STATION SITE

ADDITIONAL TRANSFORMER OR SWITCHING STATION

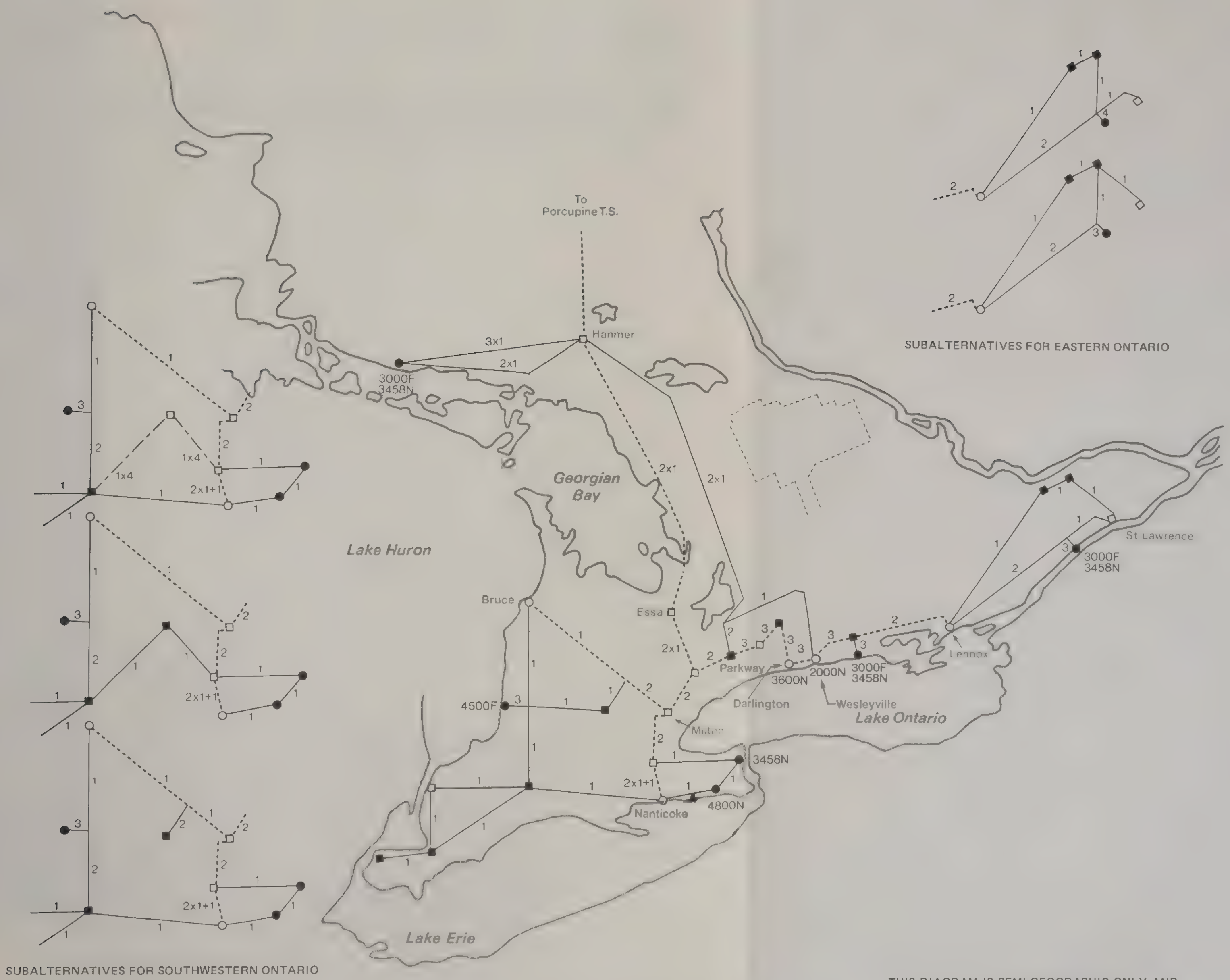
3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

2 TWO 2-CIRCUIT LINES

2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE



THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

(b) Conceptual East System Arrangement for Mid - 1990's

Alternative 1B.

This is similar to Alternative 1A. except that the additional generating station site in southwestern Ontario is located on southern Georgian Bay.

LEGEND

- - - - - - - EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY

——— ADDITIONAL 500 kV RIGHT OF WAY

— - — ADDITIONAL 230 kV LINE

○ EXISTING GENERATING STATION SITE

□ EXISTING TRANSFORMER OR SWITCHING STATION

● ADDITIONAL GENERATING STATION SITE

■ ADDITIONAL TRANSFORMER OR SWITCHING STATION

3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

2 TWO 2-CIRCUIT LINES

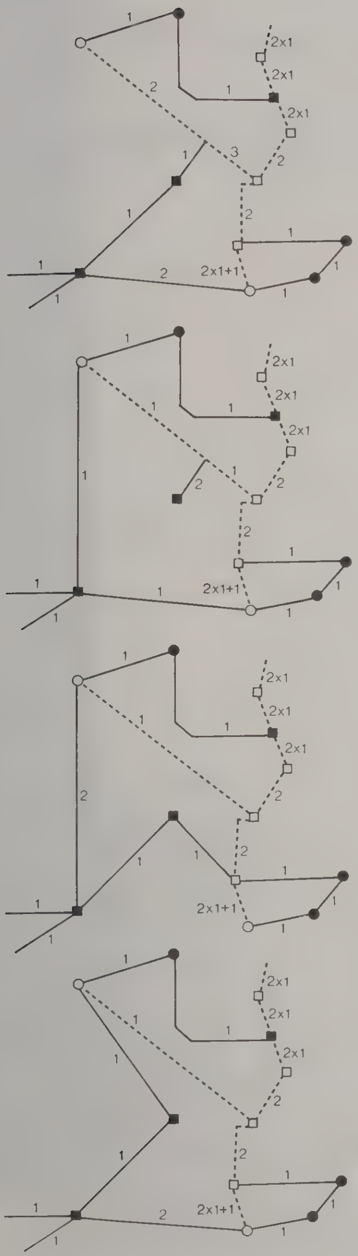
2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE

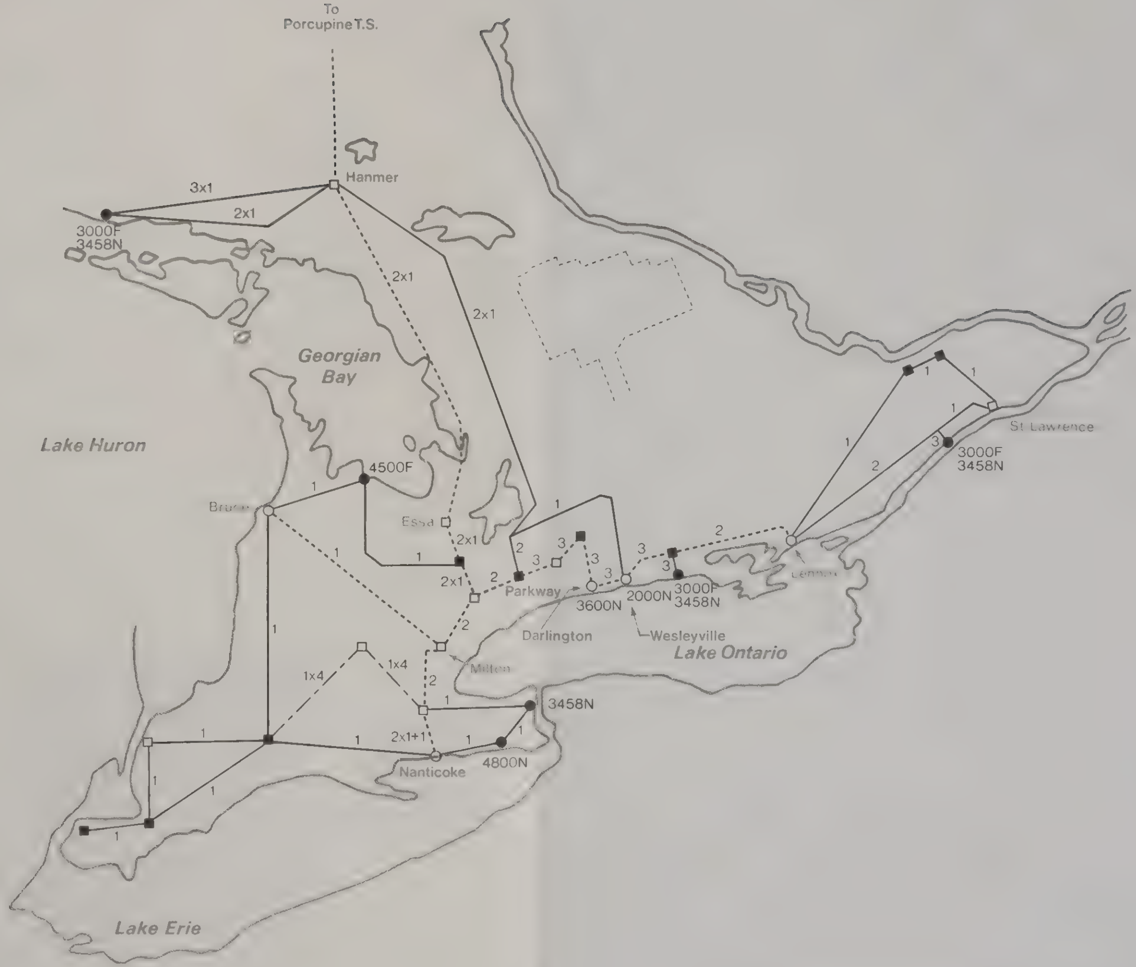
Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	13,411	10,800	1.24
Niagara - Hamilton	14,428	11,500	1.25
Central Ontario	26,221	21,300	1.23
Eastern Ontario	9,881	8,100	1.22
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 1A

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO



NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO
REFER TO ALTERNATIVE 1A

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 1B

(c) Conceptual East System Arrangement for Mid - 1990's

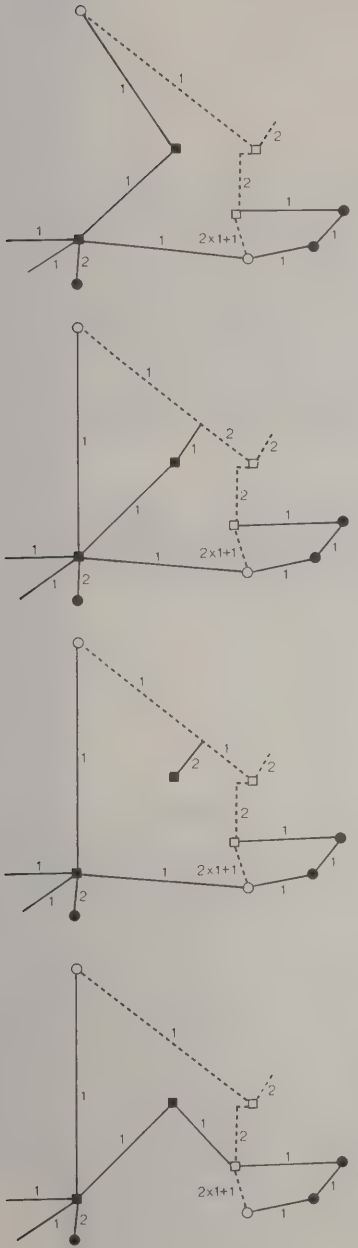
Alternative 1C.

This is similar to Alternative 1A. except that the additional generating station in southwestern Ontario is located on western Lake Erie.

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	13,411	10,800	1.24
Niagara - Hamilton	14,428	11,500	1.25
Central Ontario	26,221	21,300	1.23
Eastern Ontario	9,881	8,100	1.22
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1.26

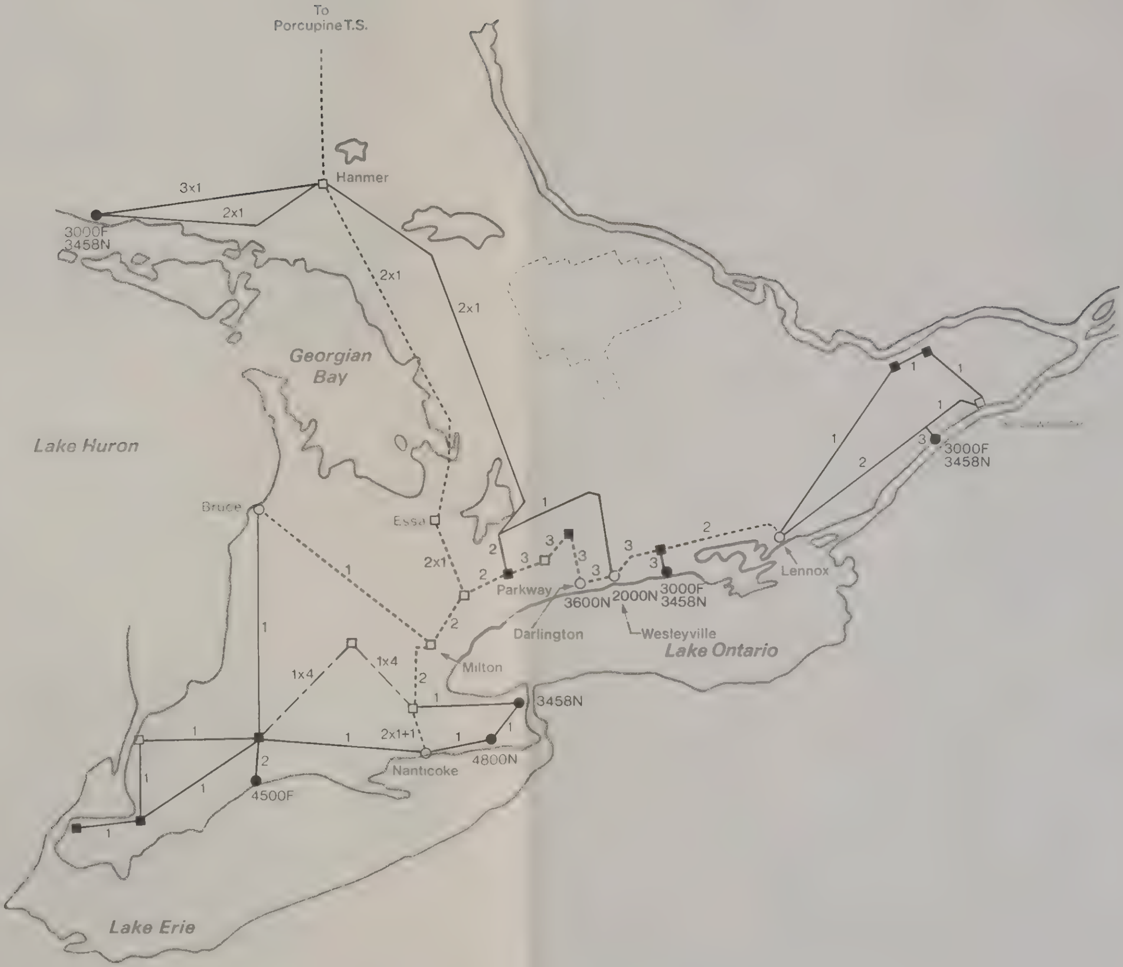
LEGEND

- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ADDITIONAL 500 kV RIGHT OF WAY
- ADDITIONAL 230 kV LINE
- EXISTING GENERATING STATION SITE
- EXISTING TRANSFORMER OR SWITCHING STATION
- ADDITIONAL GENERATING STATION SITE
- ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F — 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N — 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 — TWO 2-CIRCUIT LINES
- 2x1 — TWO 1-CIRCUIT LINES
- 1x4 — ONE 4-CIRCUIT LINE



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 1A

(d) Conceptual East System Arrangement for Mid - 1990's

Alternative 2.

No additional generation is installed in southwestern Ontario or the Niagara-Hamilton area. The amount of generation east of Toronto is increased correspondingly, compared to Alternative 1A. A second 500 kV right of way is required across the Toronto area and east of Wesleyville as shown in the diagram. Also required is a third 2-circuit 500 kV line between Claireville and Milton. For this comparison, it is assumed that the latter line is overhead, probably located on a widening of the initial right of way. However, congested conditions in this area might dictate that some circuits be underground or located on a separate right of way either of which would add an additional large cost to this alternative.

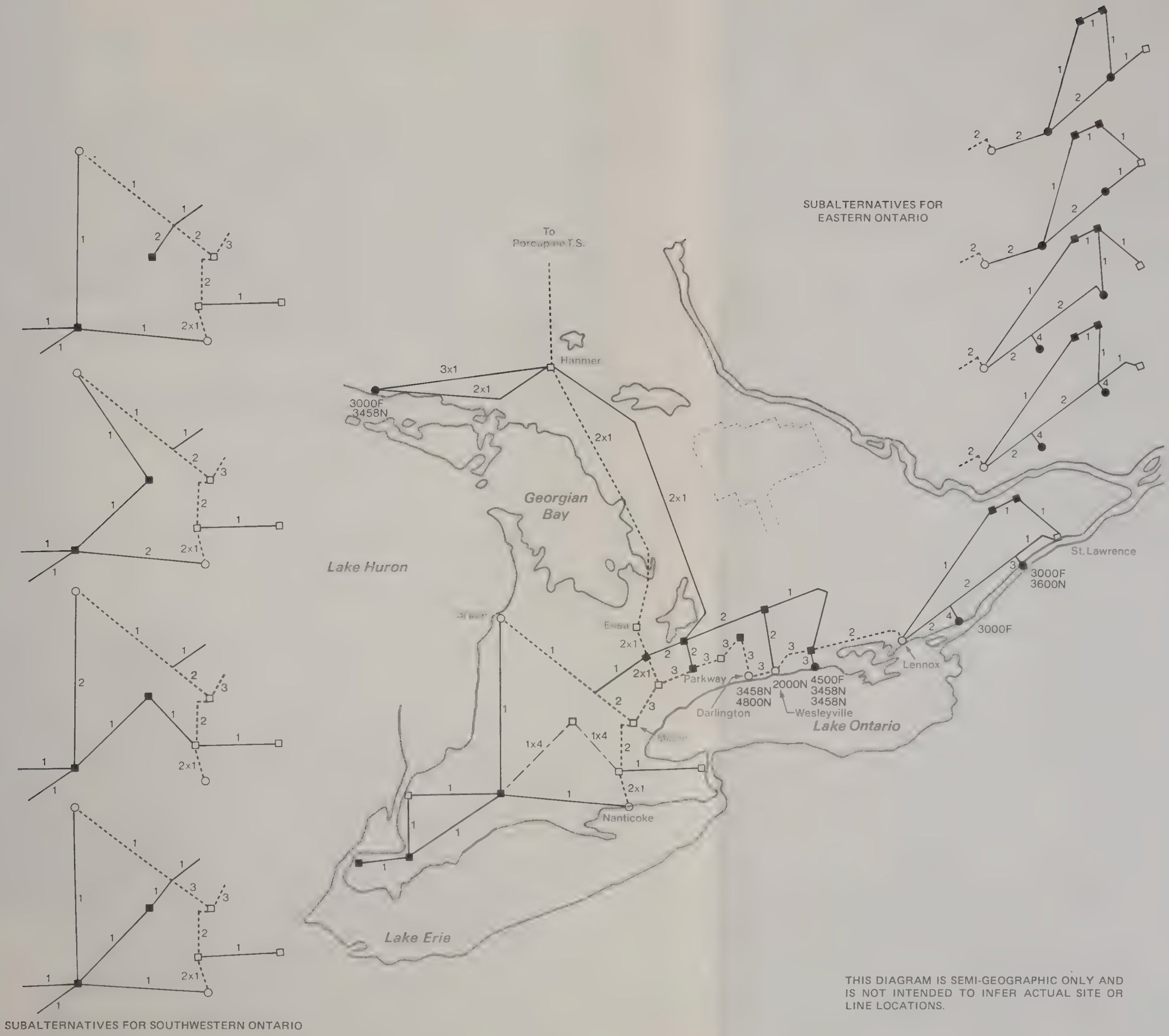
There are no 500 kV lines required in the Kitchener area for the incorporation of new generation. The additional transmission required for the Kitchener area load is assumed to be 230 kV lines from London and Middleport, but other alternatives are possible as shown in the subalternatives.

LEGEND

- - - - - - -	EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
———	ADDITIONAL 500 kV RIGHT OF WAY
— - —	ADDITIONAL 230 kV LINE
○	EXISTING GENERATING STATION SITE
□	EXISTING TRANSFORMER OR SWITCHING STATION
●	ADDITIONAL GENERATING STATION SITE
■	ADDITIONAL TRANSFORMER OR SWITCHING STATION
3000F	3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
3458N	3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
2	TWO 2-CIRCUIT LINES
2x1	TWO 1-CIRCUIT LINES
1x4	ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	8,911	10,800	0.83
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	35,837	21,300	1.68
Eastern Ontario	13,023	8,100	1.61
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 1C


SUBALTERNATIVES FOR EASTERN ONTARIO
To
Porcupine T.S.
Hanmer
3x1
2x1
3000F
3458N
Georgian
Bay
Lake Huron
Essa
Parkway
3458N
4800N
2000N
4500F
3458N
3458N
Darlington
Wesleyville
Lennox
St. Lawrence
3000F
3600N
3000F
Lake Ontario
1x4
Nanticoke
Lake Erie
THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.
SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

(e) Conceptual East System Arrangement for Mid - 1990's

Alternative 3A.

No additional generation is installed at Lennox or further east. The amount of generation installed in southwestern Ontario is increased correspondingly compared to Alternative 1A. This shift in generation results in the need for a second right of way from Wesleyville to Lennox.

Another significant transmission requirement is the need for a third 2-circuit 500 kV line between Middleport and Milton. For this comparison, this additional line is assumed to be overhead probably located on a widening of the initial right of way. However, congested conditions in this area might dictate that some circuits be underground or located on a separate right of way either of which would add an additional large cost to this alternative.

The additional generation in southwestern Ontario is located at Bruce and on southern Lake Huron.

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	14,911	10,800	1.38
Niagara - Hamilton	17,886	11,500	1.56
Central Ontario	27,721	21,300	1 30
Eastern Ontario	3,423	8,100	0.42
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1.26

LEGEND

- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ADDITIONAL 500 kV RIGHT OF WAY
- ADDITIONAL 230 kV LINE
- ○ EXISTING GENERATING STATION SITE
- □ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 2

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 3A

(f) Conceptual East System Arrangement for Mid - 1990's

Alternative 3B.

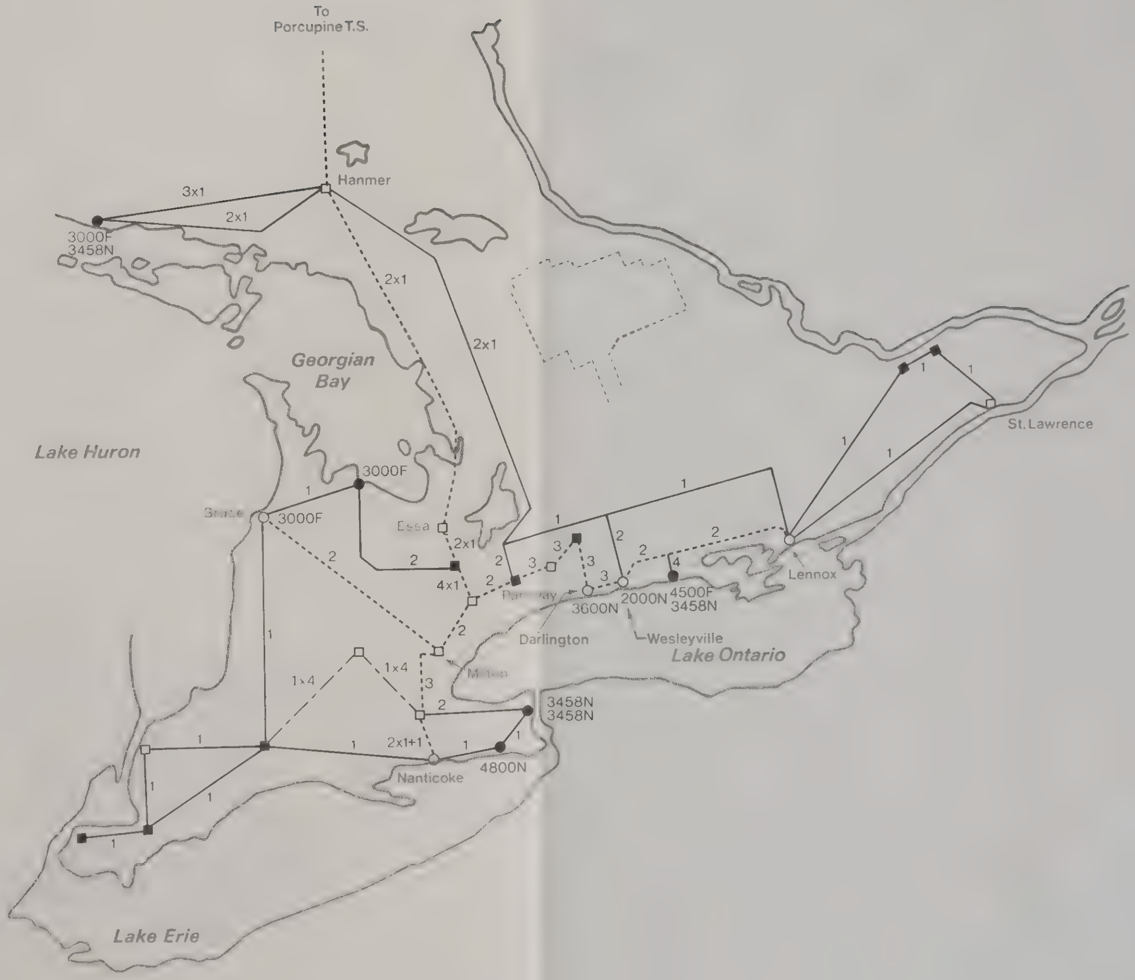
This is similar to Alternative 3A, in which no additional generation is located in eastern Ontario, except that the additional generation in southwestern Ontario is located at Bruce and on southern Georgian Bay.

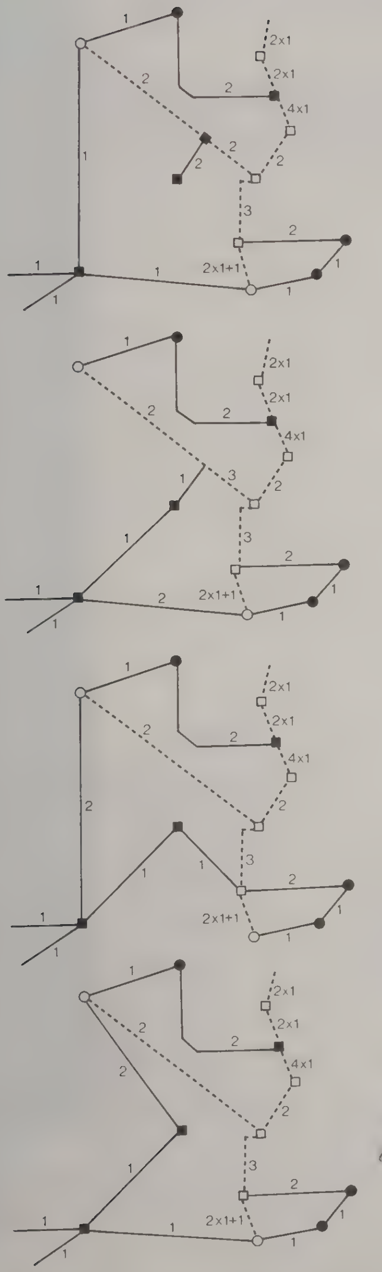
Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	14,911	10,800	1 38
Niagara - Hamilton	17,886	11,500	1 56
Central Ontario	27,721	21,300	1 30
Eastern Ontario	3,423	8,100	0.42
Northeastern Ont.	8,267	5,500	1 50
East System Total	72,208	57,200	1 26

LEGEND

- ------- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ——— ADDITIONAL 500 kV RIGHT OF WAY
- — - — ADDITIONAL 230 kV LINE
- ○ EXISTING GENERATING STATION SITE
- ◻ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.





SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 3B

(g) Conceptual East System Arrangement for Mid - 1990's

Alternative 3C.

This is similar to Alternative 3A, in which no additional generation is located in eastern Ontario, except that the additional generation in southwestern Ontario is located at Bruce and on Western Lake Erie.

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	14,911	10,800	1.38
Niagara - Hamilton	17,886	11,500	1.56
Central Ontario	27,721	21,300	1 30
Eastern Ontario	3,423	8,100	0.42
Northeastern Ont.	8,267	5,500	1.50
East System Total	72,208	57,200	1 26

LEGEND

EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY

ADDITIONAL 500 kV RIGHT OF WAY

ADDITIONAL 230 kV LINE

EXISTING GENERATING STATION SITE

EXISTING TRANSFORMER OR SWITCHING STATION

ADDITIONAL GENERATING STATION SITE

ADDITIONAL TRANSFORMER OR SWITCHING STATION

3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

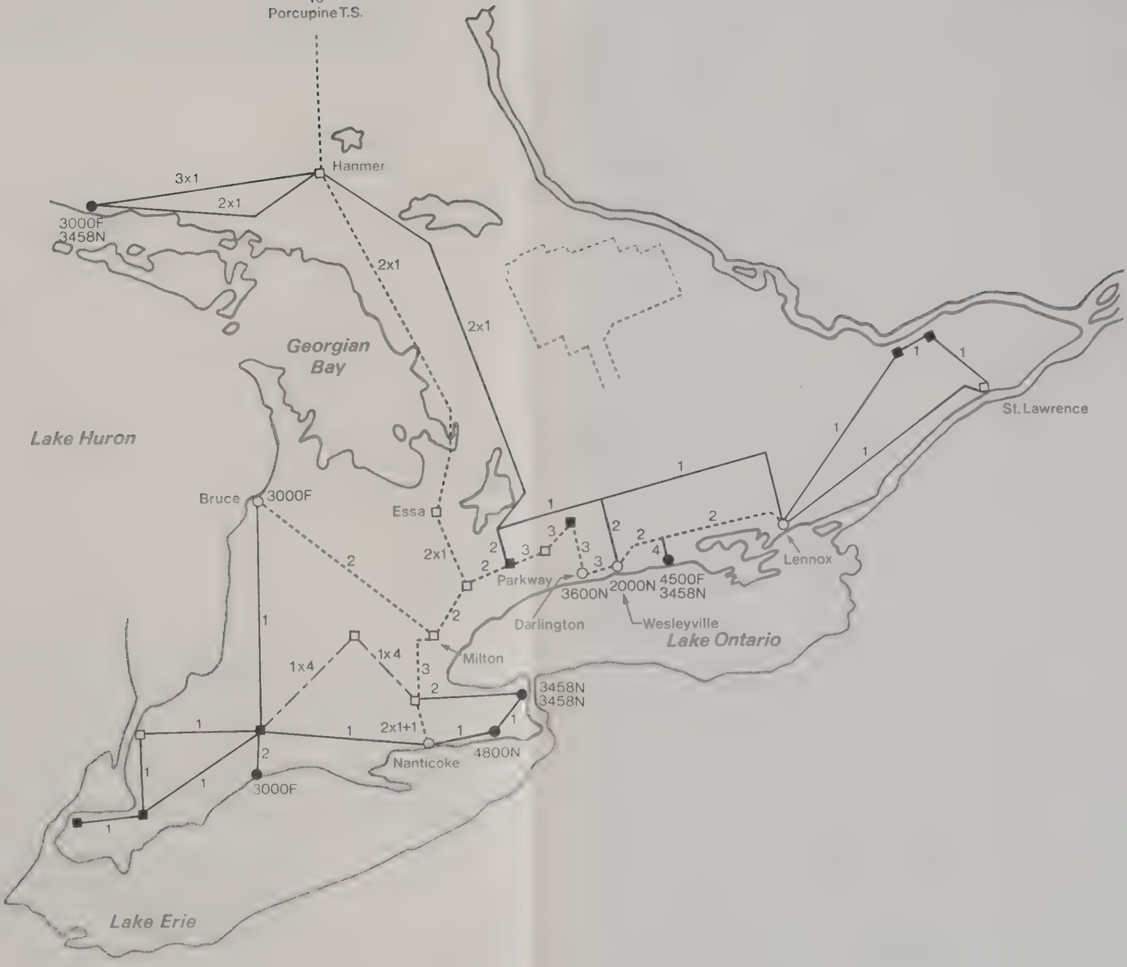
3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

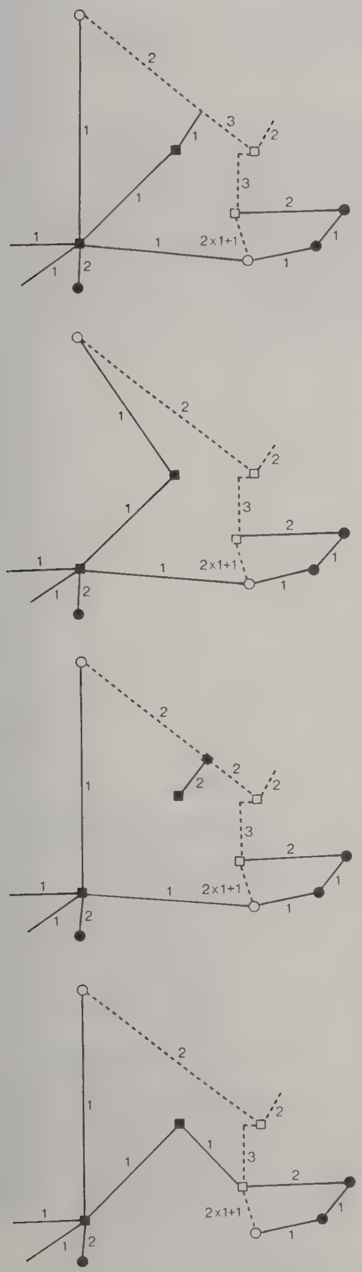
2 TWO 2-CIRCUIT LINES

2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.





SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

(h) Conceptual East System Arrangement for Mid - 1990's

Alternative 4.

No additional generation is installed in northeastern Ontario, but in the remainder of the system the generation is distributed reasonably close to the distribution of load. The most significant additional transmission requirements caused by this shift compared to Alternative 1A. are the third 2-circuit 500 kV line between Middleport and Milton with the same possible effects as discussed for Alternative 3A, and the additional right of way between Essa and the new Toronto to Sudbury right of way as shown in the diagram.

LEGEND

- - - - - - - EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY

——— ADDITIONAL 500 kV RIGHT OF WAY

— - — ADDITIONAL 230 kV LINE

○ EXISTING GENERATING STATION SITE

□ EXISTING TRANSFORMER OR SWITCHING STATION

● ADDITIONAL GENERATING STATION SITE

■ ADDITIONAL TRANSFORMER OR SWITCHING STATION

3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

2 TWO 2-CIRCUIT LINES

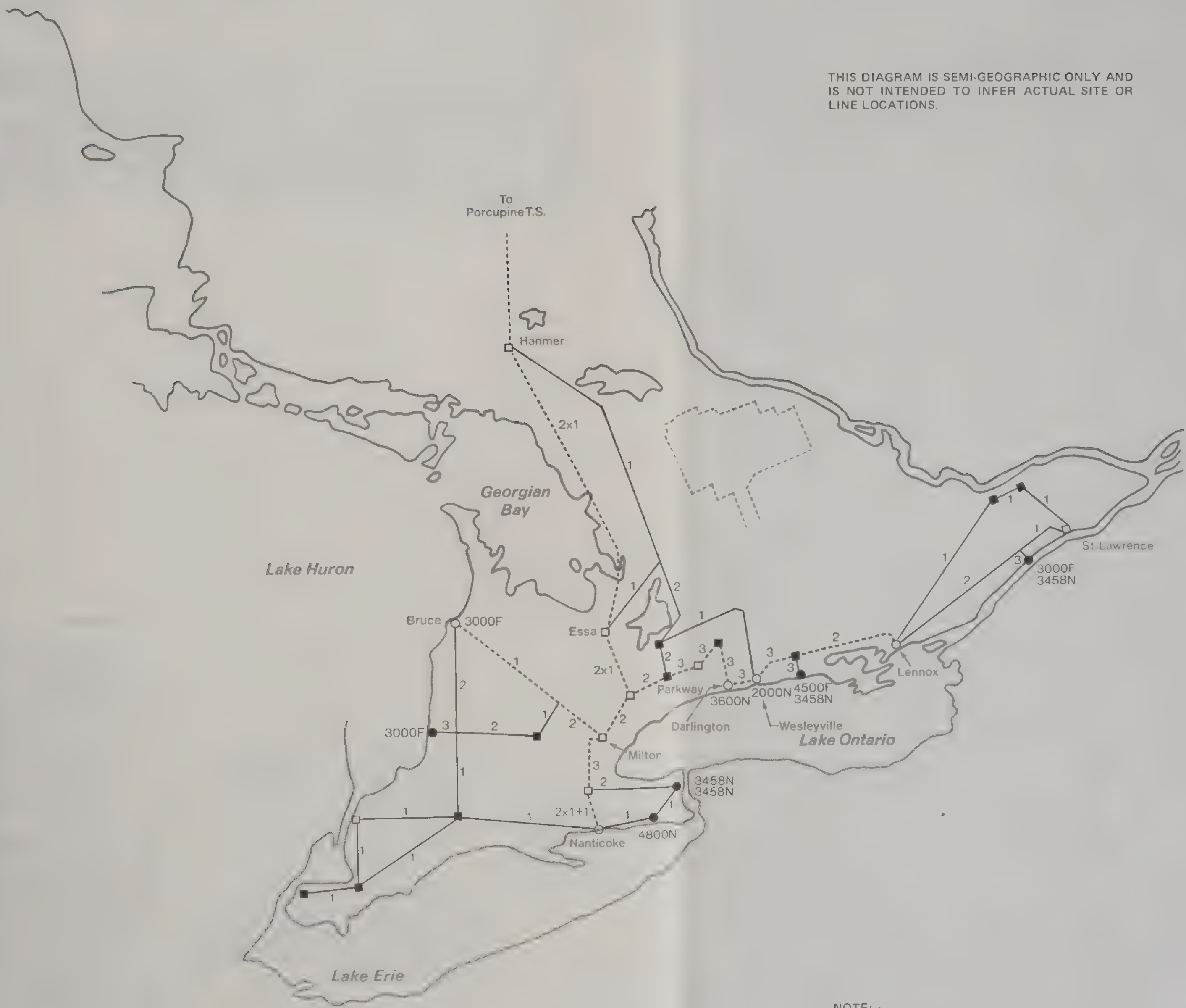
2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	14,911	10,800	1.38
Niagara - Hamilton	17,886	11,500	1.56
Central Ontario	27,721	21,300	1.30
Eastern Ontario	9,881	8,100	1.22
Northeastern Ont.	1,809	5,500	0.33
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 3C

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



NOTE: ·
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 1A.
FOR SUBALTERNATIVES IN SOUTHWESTERN ONTARIO REFER TO ALTERNATIVES 3A, 3B AND 3C

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 4

(i) Conceptual East System Arrangement for Mid - 1990's

Alternative 5A.

This shows the effect of locating an amount of generation in southwestern Ontario which is considerably in excess of the load in that area. As shown in the diagram, considerable additional 500 kV transmission is required between southwestern Ontario and the Essa and Toronto areas. The two additional generating station sites in southwestern Ontario are located on southern Lake Huron and southern Georgian Bay.

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	28,627	10,800	2.65
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	21,221	21,300	1.00
Eastern Ontario	11,381	8,100	1.41
Northeastern Ont.	4,809	5,500	0.87
East System Total	72,208	57,200	1.26

LEGEND

- - - - - - EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ——— ADDITIONAL 500 kV RIGHT OF WAY
- — - — ADDITIONAL 230 kV LINE
- ○ EXISTING GENERATING STATION SITE
- □ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO
REFER TO ALTERNATIVE 1A

(j) Conceptual East System Arrangement for Mid - 1990's

Alternative 5B.

This is similar to Alternative 5A., in which a large amount of generation is located in southwestern Ontario, except that the two additional generating station sites in southwestern Ontario are located on southern Georgian Bay and western Lake Erie.

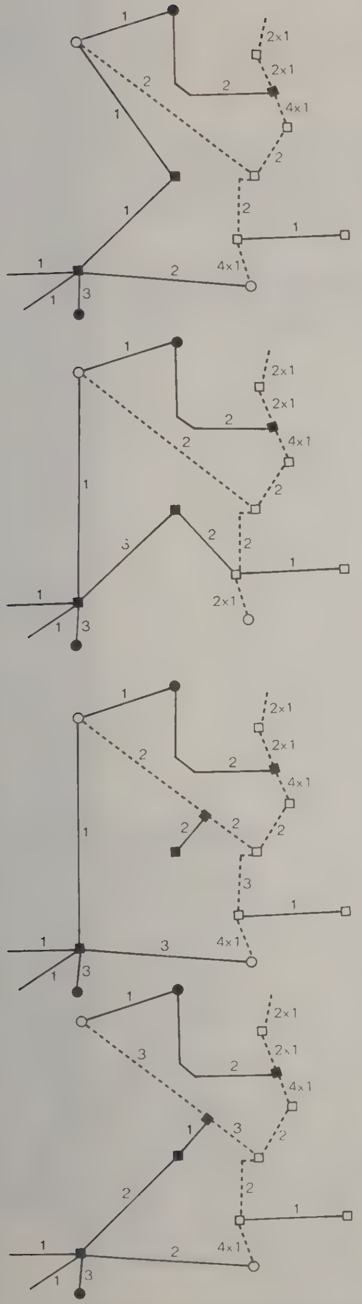
Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	28,627	10,800	2.65
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	21,221	21,300	1.00
Eastern Ontario	11,381	8,100	1.41
Northeastern Ont.	4,809	5,500	0.87
East System Total	72,208	57,200	1.26

LEGEND

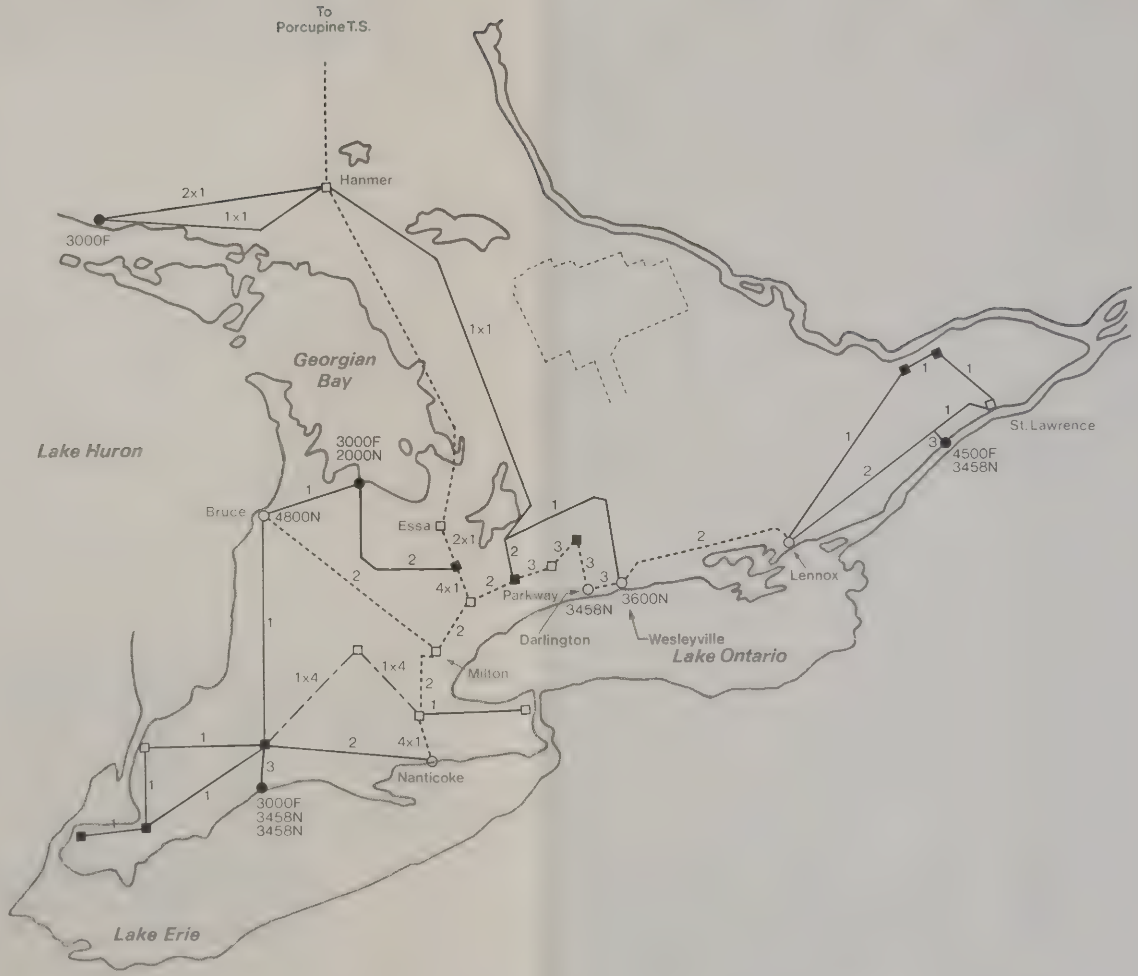
- ------- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ——— ADDITIONAL 500 kV RIGHT OF WAY
- — - — ADDITIONAL 230 kV LINE
- ○ EXISTING GENERATING STATION SITE
- □ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 5A

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO



NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 1A.

(k) Conceptual East System Arrangement for Mid - 1990's

Alternative 5C.

This is similar to Alternative 5A., in which a large amount of generation is located in southwestern Ontario, except that the two additional generating station sites in southwestern Ontario are located on southern Lake Huron and western Lake Erie.

A significant transmission requirement is the third 2-circuit 500 kV line between Milton and Claireville with the same possible affects as discussed for Alternative 3A.

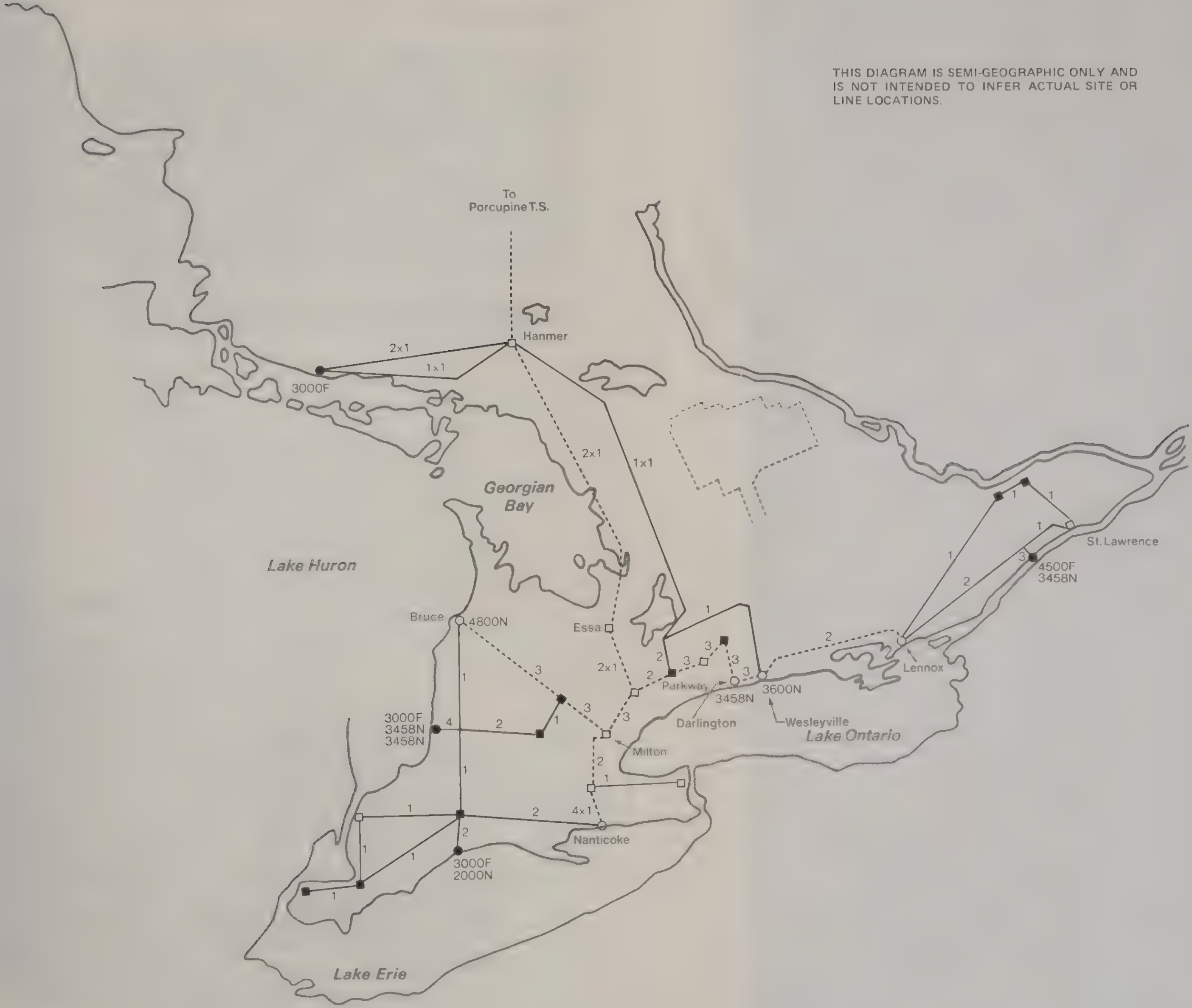
LEGEND

-------	EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
———	ADDITIONAL 500 kV RIGHT OF WAY
— - —	ADDITIONAL 230 kV LINE
○	EXISTING GENERATING STATION SITE
□	EXISTING TRANSFORMER OR SWITCHING STATION
●	ADDITIONAL GENERATING STATION SITE
■	ADDITIONAL TRANSFORMER OR SWITCHING STATION
3000F	3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
3458N	3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
2	TWO 2-CIRCUIT LINES
2x1	TWO 1-CIRCUIT LINES
1x4	ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	28,627	10,800	2.65
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	21,221	21,300	1.00
Eastern Ontario	11,381	8,100	1.41
Northeastern Ont.	4,809	5,500	0.87
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 5B

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 1A

(1) Conceptual East System Arrangement in Mid - 1990's

Alternative 6.

This is an example of a system illustrating the effect of locating a large amount of generation in the Niagara-Hamilton area. The additional transmission requirements which are significant are a third 2-circuit 500 kV line between Middleport and Milton and between Milton and Claireville. For this comparison, these lines are assumed to be overhead, probably requiring a widening of the initial Middleport to Milton to Claireville right of way. However, the congested conditions in this area might dictate that some circuits be underground or located on a separate right of way either of which would add an additional large cost to this alternative.

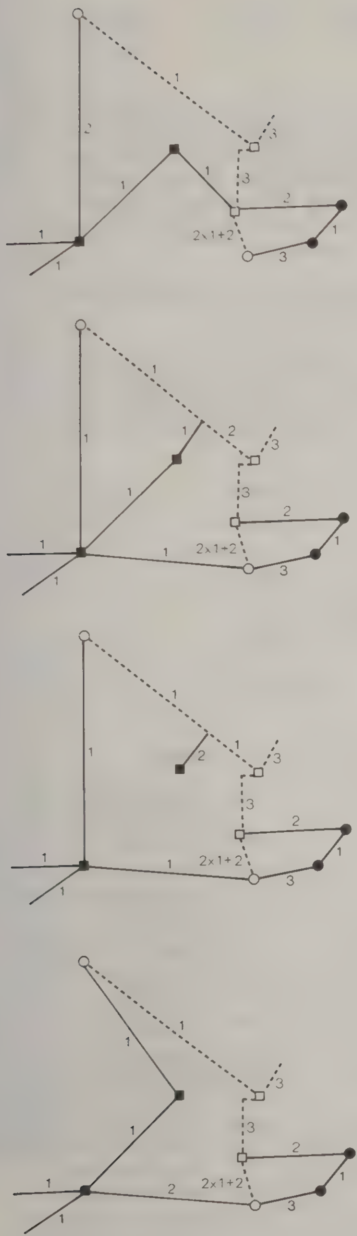
As for Alternative 2., it is possible that there would be no 500 kV facilities in the Kitchener area.

LEGEND

- - - - - - -	EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
———	ADDITIONAL 500 kV RIGHT OF WAY
—·—·—	ADDITIONAL 230 kV LINE
○	EXISTING GENERATING STATION SITE
□	EXISTING TRANSFORMER OR SWITCHING STATION
●	ADDITIONAL GENERATING STATION SITE
■	ADDITIONAL TRANSFORMER OR SWITCHING STATION
3000F	3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
3458N	3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
2	TWO 2-CIRCUIT LINES
2x1	TWO 1-CIRCUIT LINES
1x4	ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	8,911	10,800	0.83
Niagara - Hamilton	24,802	11,500	2.16
Central Ontario	19,163	21,300	0.90
Eastern Ontario	13,023	8,100	1.61
Northeastern Ont.	6,309	5,500	1.15
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 5C



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 2

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 6

(m) Conceptual East System Arrangement for Mid - 1990's

Alternative 7A.

This shows the effect of locating an amount of generation in eastern Ontario which is considerably in excess of the load in that area. A great deal of additional 500 kV transmission is required to transmit the power from eastern Ontario to Toronto, much of it on new rights of way. In addition a second right of way is required across the eastern part of the Toronto area.

The additional generating station site in southwestern Ontario is located on southern Lake Huron.

Since nuclear stations on the Ottawa River are limited to about 2000 MW (four 500 MW units), the generation program is slightly different than program LRF43P in unit sizes and total generation installed. These differences are tabulated below:

Additional Nuclear Generation and Combustion Turbine Units	LRF43P	Alternative 7A
Number of 500 MW nuclear units	0	4
Number of 850 MW nuclear units	16	12
Number of 1200 MW nuclear units	7	8
Number of 2000 MW nuclear units	1	1
Combustion Turbine Units - MW	232	232
TOTAL - MW	24,232	24,032

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	16,711	10,800	1.55
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	16,163	21,300	0.76
Eastern Ontario	26,655	8,100	3.29
Northeastern Ont.	6,309	5,500	1.15
East System Total	72,008	57,200	1.26

LEGEND

- - - - - - - EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
———— ADDITIONAL 500 kV RIGHT OF WAY
— - — ADDITIONAL 230 kV LINE
○ EXISTING GENERATING STATION SITE
□ EXISTING TRANSFORMER OR SWITCHING STATION
● ADDITIONAL GENERATING STATION SITE
■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
2 TWO 2-CIRCUIT LINES
2x1 TWO 1-CIRCUIT LINES
1x4 ONE 4-CIRCUIT LINE

SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO

(n) Conceptual East System Arrangement for Mid - 1990's

Alternative 7B.

This is similar to Alternative 7A., in which a large amount of generation is located in eastern Ontario, except that the additional generating station site in southwestern Ontario is located on southern Georgian Bay.

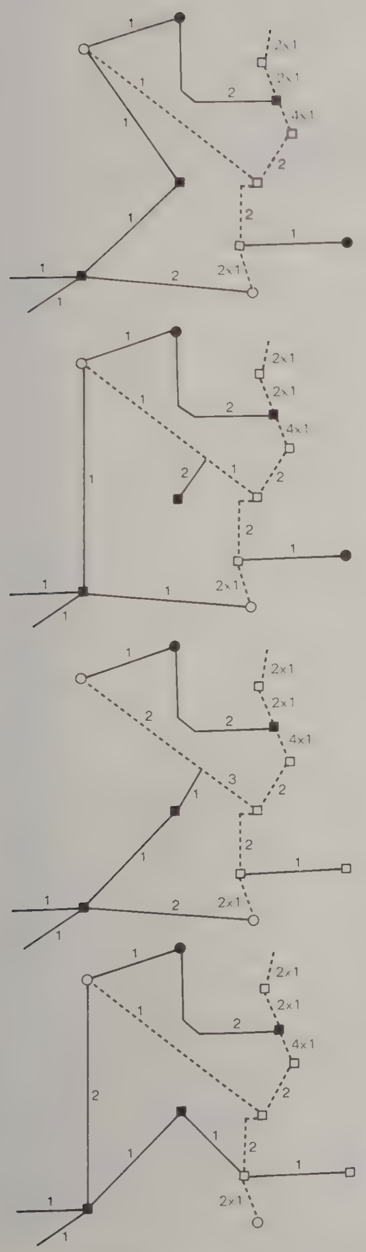
Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	16,711	10,800	1.55
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	16,163	21,300	0.76
Eastern Ontario	26,655	8,100	3.29
Northeastern Ont.	6,309	5,500	1.15
East System Total	72,008	57,200	1.26

LEGEND

- ------- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ——— ADDITIONAL 500 kV RIGHT OF WAY
- — - — ADDITIONAL 230 kV LINE
- ○ EXISTING GENERATING STATION SITE
- □ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 7A

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO.

(o) Conceptual East System Arrangement for Mid - 1990's

Alternative 7C.

This is similar to Alternative 7A., in which a large amount of generation is located in eastern Ontario, except that the additional generating station site in southwestern Ontario is located on western Lake Erie.

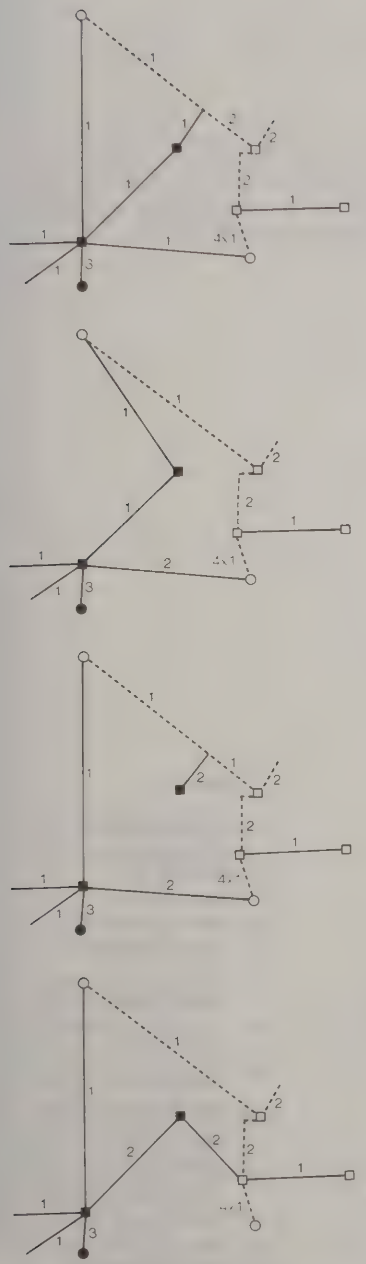
LEGEND

- EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY
- ADDITIONAL 500 kV RIGHT OF WAY
- ADDITIONAL 230 kV LINE
- EXISTING GENERATING STATION SITE
- EXISTING TRANSFORMER OR SWITCHING STATION
- ADDITIONAL GENERATING STATION SITE
- ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2x1 TWO 1-CIRCUIT LINES
- 1x4 ONE 4-CIRCUIT LINE

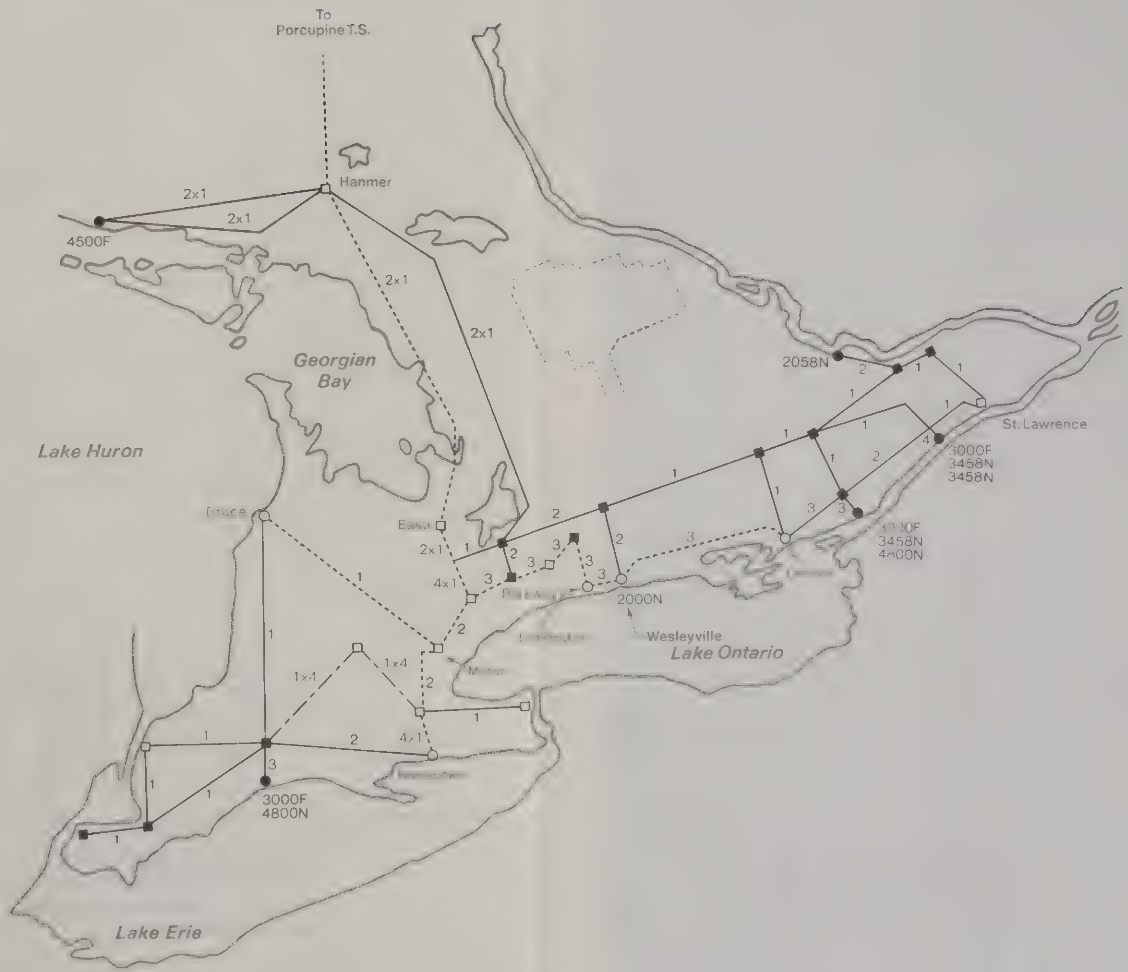
Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	16,711	10,800	1.55
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	16,163	21,300	0.76
Eastern Ontario	26,655	8,100	3.29
Northeastern Ont.	6,309	5,500	1.15
East System Total	72,008	57,200	1.26

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 7B

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.



SUBALTERNATIVES FOR SOUTHWESTERN ONTARIO



(p) Conceptual East System Arrangement for Mid - 1990's

Alternative 8A.

This shows the effect of locating a large amount of generation in northeastern Ontario and transmitting power to the loads in southern Ontario. Since the distances are long and the amounts of power large, an extensive network of 765 kV transmission is required as shown in the diagram.

LEGEND

- EXISTING, APPROVED OR RECOMMENDED 500kV RIGHT OF WAY
- ADDITIONAL 500kV RIGHT OF WAY
- ADDITIONAL 230kV LINE
- 765kV RIGHT OF WAY
- ○ EXISTING GENERATING STATION SITE
- □ EXISTING TRANSFORMER OR SWITCHING STATION
- ● ADDITIONAL GENERATING STATION SITE
- ■ ADDITIONAL TRANSFORMER OR SWITCHING STATION
- 3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)
- 2 TWO 2-CIRCUIT LINES
- 2 x 1 TWO 1-CIRCUIT LINES
- 1 x 4 ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	8,911	10,800	0.83
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	19,763	21,300	0.93
Eastern Ontario	6,423	8,100	0.79
Northeastern Ont.	30,941	5,500	5.63
East System Total	72,208	57,200	1.26

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 7C

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

SUBALTERNATIVES FOR EASTERN ONTARIO

NOTE:
FOR SUBALTERNATIVES IN SOUTHWESTERN ONTARIO REFER TO ALTERNATIVE 2

(q) Conceptual East System Arrangement for Mid - 1990's

Alternative 8B.

This is similar to Alternative 8A., in which a large amount of generation is located in northeastern Ontario, but some of it is located on sites on smaller lakes. Since nuclear stations in these locations are limited in size to about 2,000 MW, (four 500 MW units) the generation program is somewhat different than program LRF43P in unit sizes and total amount of generation installed. These differences are tabulated below:

Additional Nuclear Generation and Combustion Turbine Units	LRF43P	Alternative 8B.
Number of 500 MW nuclear units	0	12
Number of 850 MW nuclear nuits	16	8
Number of 1200 MW nuclear units	7	8
Number of 2000 MW nuclear units	1	1
Combustion Turbine Units - MW	232	290
TOTAL - MW	24,232	24,690

LEGEND

EXISTING, APPROVED OR RECOMMENDED 500kV RIGHT OF WAY

ADDITIONAL 500kV RIGHT OF WAY

ADDITIONAL 230kV LINE

765kV RIGHT OF WAY

EXISTING GENERATING STATION SITE

EXISTING TRANSFORMER OR SWITCHING STATION

ADDITIONAL GENERATING STATION SITE

ADDITIONAL TRANSFORMER OR SWITCHING STATION

3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

2 TWO 2-CIRCUIT LINES

2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	8,911	10,800	0.83
Niagara - Hamilton	6,170	11,500	0.54
Central Ontario	20,963	21,300	0.98
Eastern Ontario	6,423	8,100	0.79
Northeastern Ont.	30,199	5,500	5.49
East System Total	72,666	57,200	1.27

CONCEPTUAL EAST SYSTEM ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 8A

THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

NOTE:
FOR SUBALTERNATIVES IN EASTERN ONTARIO REFER TO ALTERNATIVE 8A
FOR SUBALTERNATIVES IN SOUTHWESTERN ONTARIO REFER TO ALTERNATIVE 2

(r) Conceptual East System Arrangement for Mid - 1990's

Alternative 9.

This shows the effect of the second right of way between Sudbury and southern Ontario being located between Sudbury and Ottawa. It also demonstrates how generating stations on the Ottawa River could be incorporated. A significant additional transmission requirement is the third 2-circuit line between Middleport and Milton with the same possible effects as discussed for Alternative 3A. The effect on the generation program of the use of smaller stations on the Ottawa River is similar to that discussed for Alternative 8B. The differences are tabulated below:

Additional Nuclear Generation and Combustion Turbine Units	LRF43P	Alternative 9.
Number of 500 MW nuclear units	0	8
Number of 850 MW nuclear units	16	8
Number of 1200 MW nuclear units	7	8
Number of 2000 MW nuclear units	1	2
Combustion Turbine Units - MW	232	232
TOTAL - MW	24,232	24,632

Area	Generation (MW)	Load (MW)	Gen/Load Ratio
Southwestern Ont.	11,911	10,800	1.10
Niagara - Hamilton	17,886	11,500	1.56
Central Ontario	22,663	21,300	1.06
Eastern Ontario	13,281	8,100	1.64
Northeastern Ont.	6,867	5,500	1.25
East System Total	72,608	57,200	1.27

LEGEND

- - - - - - - EXISTING, APPROVED OR RECOMMENDED 500 kV RIGHT OF WAY

——— ADDITIONAL 500 kV RIGHT OF WAY

— - — ADDITIONAL 230 kV LINE

○ EXISTING GENERATING STATION SITE

□ EXISTING TRANSFORMER OR SWITCHING STATION

● ADDITIONAL GENERATING STATION SITE

■ ADDITIONAL TRANSFORMER OR SWITCHING STATION

3000F 3000 MW FOSSIL-STEAM GENERATING STATION (AFTER DARLINGTON GS)

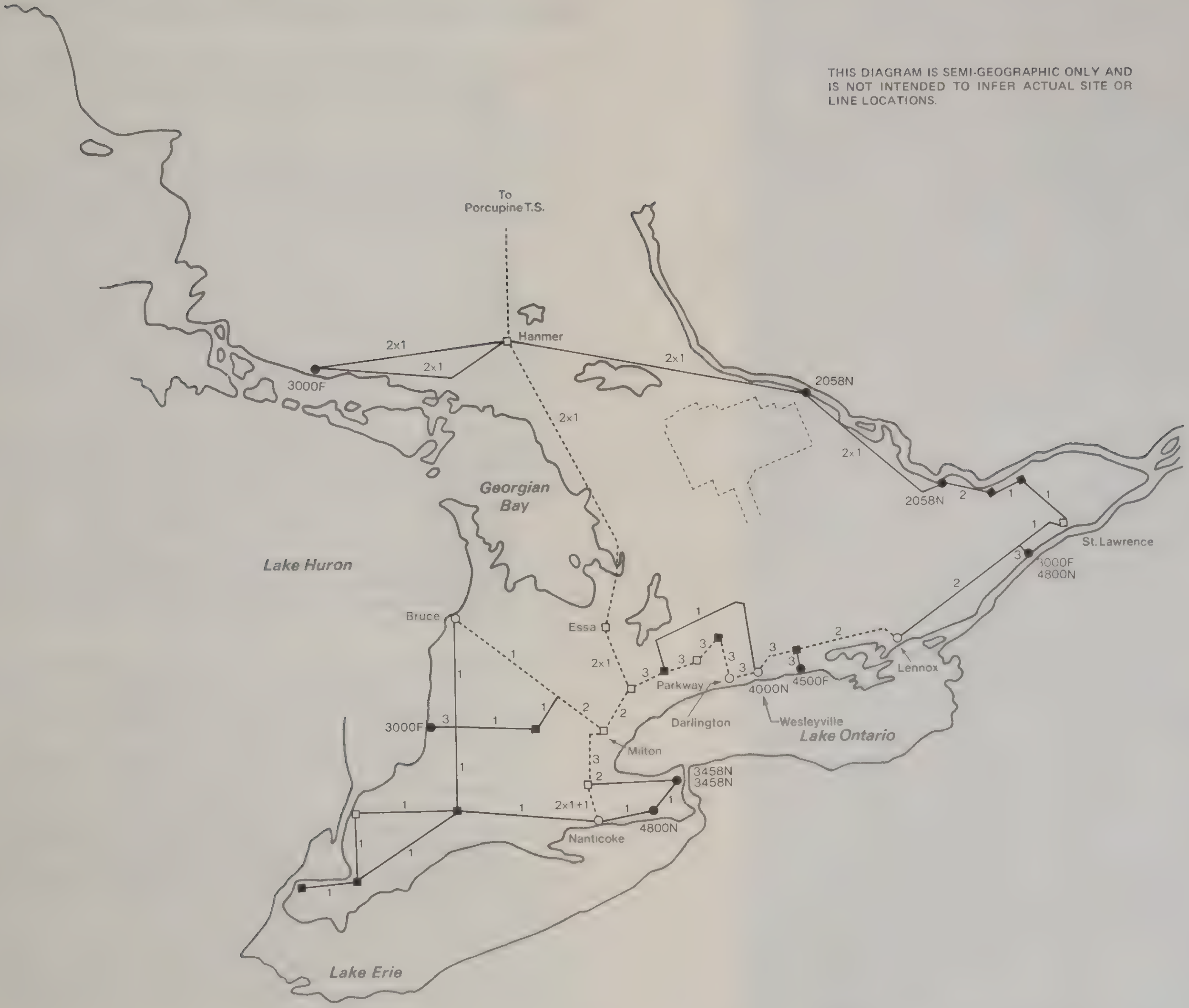
3458N 3458 MW NUCLEAR-STEAM GENERATING STATION (AFTER DARLINGTON GS)

2 TWO 2-CIRCUIT LINES

2x1 TWO 1-CIRCUIT LINES

1x4 ONE 4-CIRCUIT LINE

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 8B



THIS DIAGRAM IS SEMI-GEOGRAPHIC ONLY AND IS NOT INTENDED TO INFER ACTUAL SITE OR LINE LOCATIONS.

NOTE:
FOR SUBALTERNATIVES IN SOUTHWESTERN ONTARIO REFER TO ALTERNATIVES 1A, 1B AND 1C

CONCEPTUAL EAST SYSTEM
ARRANGEMENT FOR MID-1990's
Annual Load Growth — About 7%
ALTERNATIVE 9

C. Conclusions from Comparison of Alternative Systems Using Large Stations and Based on the 1975 Forecast of Most Probable Loads

(a) The preferred alternatives are those in which the distribution of the generation throughout the system is reasonably close to being in proportion to the load distribution.

If large amounts of generation are located in either eastern or northeastern Ontario, the amount of required additional transmission is significantly increased. This is shown in Figure 12-6. Alternatives 7., 8A., and 8B. involve considerably more miles of transmission line than Alternative 1., in which the generation is distributed throughout the system. The disadvantage of locating large amounts of generation in southwestern Ontario or the Niagara area (Alternatives 5 and 6) is not as evident from Figure 12-6 because the additional circuits are relatively short. However, the additional circuits and/or rights of way, required in the congested area west of Toronto could prove to be very costly and to have significant additional environmental implications.

Similarly, if no additional generation is installed in some parts of the system, the total amount of transmission required in the system is significantly increased (Alternatives 2 and 3 compared to Alternative 1A). Alternative 4, in which no additional generation is installed in northeastern Ontario, shows a less significant increase. However, this comparison is very dependent on the location assumed for the generation on the North Channel of Lake Huron. If this location is closer to Hanmer the increase would be greater and vice versa.

(b) Regardless of the distribution of generation, significant additional transmission facilities will be required in southwestern Ontario, in eastern Ontario and between northeastern Ontario and the Toronto area.

It is often assumed that if no generating facilities were to be located in an area, the amount of new transmission required in the area would be significantly reduced. It is apparent from an examination of the alternatives that in many areas, even if no generation is added in the area, the amount of transmission required in the area to supply the load is not significantly different than that required if generation is located in the area. The location of it may, however, be different.

(c) Where it is reasonable to do so, transmission rights of way should be located close to potential future generating station sites.

As can be seen by an examination of the subalternatives for Alternative 2, the total amount of transmission required to supply the load in the absence of generation is affected very little if it is located close to possible future generating station sites. Since this would make such sites much easier to incorporate, it is concluded that, pending a more detailed study of costs and environmental implications, it is preferable to locate transmission close to possible future generating station sites.

(d) Some alternatives have very high power losses.

This can arise from systems in which large transfers of power are required because of large deficiencies or surpluses of generation in the outlying parts of the system giving rise to a greater average distance from generation to load. For several of the alternatives, the losses are estimated to be about 300 to 600 MW greater than for the others. These are #2 in which no new generation is located west of Toronto, #7 with a large surplus of generation in eastern Ontario, #8-A and 8-B in which northeastern Ontario has a large surplus, and #4 in which no new generation is located in northeastern Ontario.

These extra power losses would add significant operating costs and since they are equivalent to extra load on the system, additional generation would be required to maintain the same level of reliability as provided by alternatives with lower losses.

(e) Generation Costs.

The development and operating costs of different generating station sites, when known, could have a large influence on the costs of the system.

12.8 The Effect of Changes in the Annual Rate of Load Growth

The alternative systems compared in Section 12.7 are all based on the 1975 forecast of most probable loads. If the actual annual load growth is different than 7%, how would this affect the appropriateness of decisions based on these alternatives? In order to study this effect, variations of alternative system 1A were developed using an illustrative lower and a higher annual load growth as described in Section 12.4. These systems are shown in Figures 12.7 and 12.8 respectively.

From the studies made, it is concluded that a change in the rate of load growth would not significantly affect the number and location of the transmission line rights of way required in 1995. It would change the number of circuits on the rights of way and the timing of the generation and transmission additions. Therefore, the systems developed for the expected annual load growth are a reasonable basis for decisions about the near-term transmission and generation requirements.

12.9 Alternative Systems Aimed at Reducing the Future Requirements for New Bulk Transmission

The objective of these alternatives is to provide systems that are capable of supplying the load with adequate reliability, but of doing so with less additional bulk transmission than required by the alternatives discussed in Section 12.7.

In order to meet this objective, generation is added in each area to provide a reliable supply to the load in the area. In some areas smaller generating units are used because they result in lower costs than the unit sizes used in the alternatives described in Section 12.7. The alternatives illustrate how a reduction in transmission could influence generation location and affect the capital cost of the generation and transmission.

To analyze these alternatives, the East System was divided into the seven areas shown in Figure 12-9. This figure shows the 1995 load for each area based on the 1975 forecast of most probable loads. Also shown is the assumed transfer capability between areas in 1995. These are the approximate capabilities which can be achieved with the existing and approved bulk power transmission on the assumption that the intermediate loads would not be tapped to the bulk power transmission.

The area identified as the remainder of the system comprises load in the Niagara, Hamilton and Toronto areas and the area along Lake Ontario to Kingston. This area contains about 65% of the total East System load. It can be considered as a single area because of the existence of a 500 kV corridor stretching from the Lennox Station through Toronto, Hamilton and to Nanticoke. The Bruce GS is considered part of this area because of the 500 kV line from Bruce GS to the 500 kV lines in the Toronto-Hamilton Area. The Bruce B Generating Station was planned to be brought into service starting in 1982 in Program LRF43P, and in 1983 in the current reduced program. This nuclear station, comprising four 750 MW units must be located at Bruce, because Ontario Hydro has no other site on which it could be located by 1983. However, to illustrate the effect of limiting the amount of 500 kV transmission from Bruce GS to the initial 500 kV 2-circuit line, it is assumed that this 4-750 MW nuclear station would be located elsewhere in the "Remainder of the East System".

The remaining areas and their load as a percent of the East System total are:

Sarnia	2
Windsor	3
London	5
Kitchener	6
Northeast	9
Ottawa-Cornwall	10

Generating systems capable of supplying the 1995 area loads were devised. In determining the size, type, amount, and cost of new generating capacity to be added to each area, the following guidelines were used:

(a) The generation in each area is made up of the existing generation and the additional generation necessary to achieve a loss of load probability in each area of about 0.4 in 2400. (With this loss of load probability in each area, the total East System loss of load probability is about 2.8 in 2400, i.e., the same as provided by LRF43P.)

(b) Minimum unit size is limited to 200 MW.

(c) The total quantity of nuclear generation added is close to that added in LRF43P. This generation is distributed among the areas in such fashion that the sum of nuclear and hydraulic generation in each area except Sarnia is roughly in proportion to the load in the area.

Figure 12-11 summarizes four alternative generating systems meeting these guidelines and compares them with the generation in Program LRF43P. The capital costs shown in the table are for generation only; i.e., they do not include the costs of transmission. They are adjusted to bring them to a comparable basis with Program LRF43P, in terms of nuclear capacity and area reliability.

The four cases use the following assumptions:

Case	Transfer Capability of Interarea Transmission	Additional Generation
1	As shown in Figure 12-9.	No units larger than 500 MW.
2	As shown in Figure 12-9	1x2000N and 7x1200N, as in LRF43P, in the "Remainder of the East System". 850N units in Northeast. Other units larger than in Case 1 where this leads to lower capital costs.
3	Transmission capability from Northeast to "Remainder of System" as in Cases 1 and 2; all other interarea transmission capability increased by 500 MW.	Similar basis as in Case 2, but fewer units are installed.
4	Same as Case 3, except the transmission is increased into the Kitchener area, enabling it to be fully incorporated into the load and generation of the "Remainder of the East System".	Same as Case 3, except Kitchener area generation replaced by larger units on the "Remainder of the East System".

In Program LRF43P, with which these four cases are compared, the transmission is adequate to enable reserve generation in each area to be supplied to any other area. This enables Program LRF43P to use some larger units than Cases 1, 2, 3, and 4.

Figures 12-12, 12-13, 12-14, 12-15 and 12-16 show the main transmission associated with each of the cases and Program LRF43P. For the latter, the system shown is alternative 1A of Section 12.7, for which the total generation is distributed among the various areas of the province roughly in proportion to the loads in the areas. All five alternatives assume that adequate sites for major new generating stations will be available as required in the various areas. This assumption may not be realizable but is made in order to illustrate the effects of placing limitations on interarea transmission capability. None of the five figures shows the additional local transmission facilities that will be required to distribute power to the loads in each of the seven areas.

The following table summarizes the estimated capital costs (in 1985 dollars) of the additional generation and additional bulk power transmission associated with each of the four cases, compared with Program LRF43P. For each comparsion, it shows both the total additional costs and the non-common additional costs. The latter are the pertinent values for comparison purposes.

Capital Cost Comparison of Cases 1, 2, 3, and 4, With Program LRF43P All Costs in Billions of $1985

	Total Additional Costs			Non-Common Additional Costs*		
Case 1 and LRF43P	Case 1	LRF43P	Advantage of LRF43P	Case 1	LRF43P	Advantage of LRF43P
Transmission	2.92	4.49	-1.57	1.39	2.96	-1.57
Generation	49.73	38.51	11.22	49.73	38.51	11.22
Total	52.65	43.00	9.65	51.12	41.47	9.65
Case 2 and LRF43P	Case 2	LRF43P	Advantage of LRF43P	Case 2	LRF43P	Advantage of LRF43P
Transmission	2.84	4.49	-1.65	1.33	2.98	-1.65
Generation	45.32	38.51	6.81	22.94	16.13	6.81
Total	48.16	43.00	5.16	24.27	19.11	5.16
Case 3 and LRF43P	Case 3	LRF43P	Advantage of LRF43P	Case 3	LRF43P	Advantage of LRF43P
Transmission	3.11	4.49	-1.38	1.61	2.99	-1.38
Generation	42.99	38.51	4.48	21.04	16.56	4.48
Total	46.10	43.00	3.10	22.65	19.55	3.10
Case 4 and LRF43P	Case 4	LRF43P	Advantage of LRF43P	Case 4	LRF43P	Advantage of LRF43P
Transmission	3.19	4.49	-1.30	1.52	2.82	-1.30
Generation	41.95	38.51	3.44	15.24	11.80	3.44
Total	45.14	43.00	2.14	16.76	14.62	2.14

* Costs of transmission facilities or generating units which are common to LRF43P and the case being compared to it are not included.

It is clear from the table that:

(a) bulk power transmission costs are very small compared to the generation costs;

(b) when Cases 1, 2, 3, and 4 are compared to LRF43P, the reductions in non-common transmission costs are outweighed by the increases in non-common generation costs: and

(c) from the capital cost viewpoint, Program LRF43P is preferable to Cases 1, 2, 3, and 4.

There are shortcomings in this analysis, which cannot be overcome at this time. These include:

(a) In the cost comparison, all capital costs are computed using the 1985 costs per kilowatt of four-unit generating stations located on the shores of the Great Lakes and the major rivers, and hence employing once-through condenser cooling water systems. In Cases 1, 2, and 3, it is assumed that suitable inland sites for large generating stations can be located relatively near Kitchener. This is a dubious assumption. In addition, it would involve increased costs for condenser cooling systems, fossil fuel delivery, and exclusion areas around nuclear stations, which are not included in the data shown in Figure 12-10.

(b) No account is taken of the year-by-year course of development that would be followed up to 1995. Taking account of this would increase the costs of Cases 1, 2, 3, and 4, because it would involve stretching out the development of each of the small generating stations. By contrast, Program LRF43P would enable each generating station to be developed on a continuous short schedule at lower cost.

(c) Generation installed on new sites in the various areas could not be brought into service before the late 1980's. The load in the areas could not be supplied with adequate reliability until this time without the addition of interarea transmission, but no account has been taken of such additions.

(d) No provision has been made for interconnections with other utilities as in the transmission system associated with LRF43P. Therefore, Cases 1, 2, 3, and 4 will have an inherently lower reliability.

(e) In Cases 1 to 4, Bruce A is connected to the load in the "Remainder of the East System" by a 2-circuit 500 kV line. Therefore, the reliability of this station is significantly less in Cases 1 to 4 than in Program LRF43P with which it is compared.

In view of these factors, it is apparent that the capital cost advantage of LRF43P will be greater than shown in the above table.

Other cost factors to be considered include the cost of operation, maintenance, fuel, and transmission system losses. All of these considerations would enhance the economic advantage of LRF43P, with the possible exception of transmission system losses. While the economic worth of the transmission losses cannot be accurately estimated, it is clear

that their value would not offset the conclusion reached from consideration of the other factors, which is, that Program LRF43P will have capital cost and operating, maintenance, and fuel cost advantages over Cases 1, 2, 3, and 4.

Compared to Cases 1, 2, 3 and 4, the fully integrated system provided by Program LRF43P has a greater flexibility to incorporate alternative sitings of new generating stations and to adapt to future changes in patterns of area load growths.

In summary, even though this study is hypothetical, in that it does not include many shortcomings of the alternatives using smaller units which in fact make them unrealistic, it shows that the fully integrated system using large stations and units is better on the basis of capital costs. Other advantages of the fully integrated system are:

(i) Lower operating, maintenance and fuel costs

(ii) Greater flexibility for future development

It is therefore, concluded that further work to be reported later should be restricted to a comparison of fully integrated system alternatives.